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Analysis of Commercial Cylinder Gases of Nitric Oxide, Sulfur Dioxide, and Carbon Monoxide at Source Concentrations: Results of Audit 5

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FINAL REPORT

ANALYSIS OF COMMERCIAL CYLINDER GASES OF NITRIC OXIDE, SULFUR DIOXIDE, AND CARBON MONOXIDE AT SOURCE CONCENTRATIONS

Results of Audit 5

by

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16. ABSTRACT

Manufacturers of commercial cylinder gases supply standards with a certified analysis and a statement of accuracy. Generally, the level of accuracy is specified as a percentage of the component value. To ascertain the accuracy of analyses of commercially available cylinder gases, the Environmental Protection Agency (EPA) has initiated a national performance audit program of commercial gas manufacturers. Audit 1 was performed in June 1978, Audit 2 was performed in January 1979, Audit 3 was performed in September 1979, and Audit 4 was performed in April 1980. A summary of these results is included in this report.

The purpose of Audit 5 was to analyze the concentration of cylinder gases purchased from a representative sample of manufacturers and determine the accuracy of the manufacturers' certified concentrations. Audit 5 included cylinders of sulfur dioxide (SO_2) at 90 and 500 ppm, nitric oxide (NO) at 50 and 300 ppm, and carbon monoxide (CO) at 50 and 500 ppm obtained from 14 different manufacturers. Audit 5 was performed from March through June 1981. Audit 5 results are summarized in this report.

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SECTION 1

SUMMARY

Manufacturers of commercial cylinder gases supply standards with a certified analysis and a statement of accuracy. Generally, the level of accuracy is specified as a percentage of the component value. To ascertain the accuracy of analyses of commercially available cylinder gases, the Environmental Protection Agency (EPA) has initiated a national performance audit program of commercial gas manufacturers. Audit 1 was performed in June 1978, Audit 2 was performed in January 1979, Audit 3 was performed in September 1979, and Audit 4 was performed in April 1980. Audits 1 and 2 included cylinders of sulfur dioxide and nitric oxide at source concentrations. Results of these audits were reported in "Analysis of Commercial Cylinder Gases of Nitric Oxide and Sulfur Dioxide at Source Concentrations - Results of Audits 1 and 2."* Audit 3 included cylinders of sulfur dioxide, nitric oxide, and carbon monoxide, and a reanalysis of cylinder gases included in Audit 2. Results of Audit 3 are included in "Analysis of Commercial Cylinder Gases of Nitric Oxide, Sulfur Dioxide, and Carbon Monoxide - Results of Audit 3."* Audit 4 included cylinders of sulfur dioxide, nitric oxide, and carbon monoxide, and a reanalysis of cylinder gases included in Audit 3. Results of Audit 4 are included in "Analysis of Commercial Cylinder Gases of Nitric Oxide, Sulfur Dioxide, and Carbon Monoxide - Results of Audit 4."* A summary of these results is also included in Tables 8 through 10 of this report.

The purpose of Audit 5 was to analyze the concentration of cylinder gases purchased from a representative sample of manufacturers and determine the accuracy of the manufacturers' certified concentrations. A reanalysis of the cylinder gases analyzed in Audit 4 was not performed during Audit 5, since stability of these gases had been demonstrated in Audits 2 through 4.

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*Report available from the Quality Assurance Division, Environmental Monitoring Systems Laboratory, Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Audit 5 included cylinders of sulfur dioxide (SO_2) at 90 and 500 ppm, nitric oxide (NO) at 50 and 300 ppm, and carbon monoxide (CO) at 50 and 500 ppm obtained from 14 different manufacturers. Audit 5 was performed from March through June 1981. The procedure used by Research Triangle Institute (RTI) to analyze Audit 5 cylinder gases was EPA's "Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors" (Protocol No. 1, June 15, 1978). Audit 5 results are summarized in Table 1.

TABLE 1. SUMMARY OF RESULTS FOR AUDIT 5 OF COMMERCIAL CYLINDER GASES FOR SULFUR DIOXIDE, NITRIC OXIDE, AND CARBON MONOXIDE

Manufacturer	Sulfur Dioxide Nominal Conc. (ppm)	Sulfur Dioxide Percent Accuracy	Nitric Oxide Nominal Conc. (ppm)	Nitric Oxide Percent Accuracy	Carbon Monoxide Nominal Conc. (ppm)	Carbon Monoxide Percent Accuracy
AGA Burdox, Inc.	500	6.1	300	-0.7	500	-1.4
	90	9.0	50	-2.9	50	-2.3
Air Monitoring Gas Company	500	*	300	-2.3	500	0.4
	90		50	-6.0	50	8.2
Airco Industrial Gases	500	1.4	300	1.0	500	0.4
	90	2.3	50	-2.8	50	4.0
Air Products & Chemicals, Inc.	500	-4.6	300	-1.0	500	-13.0
	90	-31.7	50	-4.4	50	-15.9
Big Three Industries	500	26.1	300	-4.9	500	-0.6
	90	38.4	50	-6.8	50	0.0
Ideal Gas Products	500	11.9	300	0.4	500	3.1
	90	6.0	50	-1.1	50	0.4
Liquid Carbonic Corp.	500	-3.5	300	-2.0	500	0.6
	90	-0.2	50	1.7	50	0.2
Matheson Gas Products	500	-7.0	300	-0.7	500	-13.5
	90	-9.3	50	-3.0	50	-6.5
MG Scientific Gas Products	500	42.8	300	8.1	500	0.8
	90	112	50	20.0	50	-6.7
North East Cryogenics	500	8.2	300	-0.4	500	3.3
	90	12.1	50	1.6	50	-1.0
Scientific Gas Products, Inc.	500	6.2	300	-1.3	500	1.0
	90	11.8	50	-11.4	50	-16.3
Scott Environmental Tech., Inc.	500	-0.4	300	-0.3	500	0.2
	90	3.2	50	-1.1	50	0.8
Scott-Marrin, Inc.	500	-0.4	300	1.0	500	- 0.6
	90	0.2	50	-1.0	50	0.0
Linde Div. of Union Carbide	500	6.8	300	0.6	500	3.3
	90	-40.5	50**	3.1	50	1.8

*Company does not supply SO_2.
**Nominal 50 ppm ordered but 530 ppm shipped.
Percent accuracy = 100(Manufacturer - RTI)/RTI.

SECTION 2

INTRODUCTION

Manufacturers of commercial cylinder gases supply gas mixtures with a certified analysis and a statement of accuracy. The purpose of this project was to analyze cylinders obtained from a representative sample of gas manufacturers and compare the measured concentrations with the manufacturers' quoted analyses. The gases of interest were mixtures of NO, CO, and SO_2 in nitrogen.

A survey was conducted of manufacturers that routinely provide gas mixtures; these companies are listed in Table 2. Fourteen of the thirty-three companies shown in Table 2 were selected to supply gas cylinders for analysis and are listed in Table 3. The other companies were not included because: (1) they do not supply gases used in environmental studies, or (2) they do not blend and analyze their own gases but merely label another manufacturer's product.

Gas mixtures were obtained through a third party to maintain anonymity. Cylinder gases for Audits 1 through 4 were procured by anonymous third parties located in the eastern part of the United States. In an attempt to evaluate the accuracy of cylinder gases produced by the manufacturers' different production facilities throughout the country, a third party located in the western part of the United States was chosen to procure gases for Audit 5. Table 3 includes a listing of the production facilities for gases procured for Audits 1 through 5. The nominal concentrations ordered were:

(1) 300 ppm NO, balance nitrogen.
(2) 500 ppm SO_2, balance nitrogen.
(3) 500 ppm CO, balance nitrogen.
(4) 50 ppm NO, balance nitrogen.
(5) 90 ppm SO_2, balance nitrogen.
(6) 50 ppm CO, balance nitrogen.

TABLE 2. SURVEY OF CYLINDER GAS MANUFACTURERS

AGA Burdox, Inc.
Air Monitoring Gas Company
Air Products and Chemicals, Incorporated
Airco Industrial Gases
Automotive Environmental Systems, Incorporated
Big Three Industries
Chemetron Industrial Gases
Edmond Scientific Company
Essex Chemical Corporation
Ideal Gas Products
J. T. Baker Chemical Company
J. W. Goodliffe Air Products Company
Liquid Carbonic Corporation
Matheson Gas Products
MG Scientific Gases
National Welders Supply Company, Incorporated
New England Nuclear
Northeast Cryogenics
Nuclear Sources and Services, Incorporated
Ohio Chemical and Manufacturing Company
Pipe Welding Supply Company, Incorporated
PPG Industries, Incorporated
Puritan Compressed Gas Corporation
Scientific Gas Products, Incorporated
Scientific Products, Division of American Hospital Supplies
Scott Environmental Technology, Incorporated
Scott-Marrin, Incorporated
Stauffer Chemical Company
Sulfrian Cryogenics, Incorporated
Supelco, Incorporated
Texas Gulf, Incorporated
Union Carbide Corporation, Linde Division
Virginia Chemical, Incorporated

TABLE 3. CYLINDER GAS MANUFACTURERS INCLUDED IN AUDIT PROGRAM

Manufacturer	Production Facility	
	Audits 1-4	Audit 5
AGA Burdox, Inc.	*	Detroit, MI
Air Monitoring Gas Gas Company	*	Royal Oak, MI
Airco Industrial Gases	Research Triangle Park, NC	Riverton, NJ Port Allen, LA
Air Products and Chemicals, Inc.	Tamaqua, PA	Tamaqua, PA La Porte, TX
Big Three Industries	Houston, TX	Houston, TX
Ideal Gas Products	Edison, NJ	Edison, NJ
Liquid Carbonic Corp.	Baltimore, MD	Pasadena, TX
Matheson Gas Products	Morrow, GA	La Porte, TX
MG Scientific Gases	Somerville, NJ	Somerville, NJ
North East Cryogenics	Newtonville, MA	Newtonville, MA
Scientific Gas Products, Inc.	South Plainfield, NJ	Pasadena, TX Brighton, CO
Scott Environmental Technology, Inc.	Plumsteadville, PA	San Bernardino, CA
Scott-Marrin, Inc.	Riverside, CA	Riverside, CA
Union Carbide Corp., Linde Division	East Chicago, IN	East Chicago, IN Houston, TX

*Company not included in audit survey.

Specifications of the type of analysis or the type of cylinder (steel or aluminum) were not included on the purchase request. To avoid compromising the audit, it was necessary to purchase the cylinder gases with the presumption that they would be used for routine purposes. The only specifications given to the manufacturers were cylinder size, component, nominal concentration levels, and a request for a certified analysis. The request for a certified analysis did not specify that manufacturers should analyze cylinder gases according to EPA's Traceability Protocol No. 1.

SECTION 3

CYLINDER GAS ANALYSIS AND TRACEABILITY PROCEDURE

Cylinders were received and grouped by manufacturer, pollutant species, and concentration. The NO, CO, and SO_2 analyses were performed separately using source emission analyzers. Each commercial cylinder was analyzed three times. Between analyses a National Bureau of Standards-Standard Reference Material (NBS-SRM) or a gas manufacturers precision standard (GMPS) that met the EPA average degradation criterion of less than 1 percent per month was introduced as a control check on the analyzer. All procedures met or exceeded the guidelines set forth in EPA's "Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors" (Protocol No. 1, June 15, 1978). Prior to analysis of the commercial cylinders, RTI was required to participate in an EPA audit for NO, CO, and SO_2.

3.1 ANALYSIS OF NITRIC OXIDE CYLINDERS

A Thermo-Electron Corporation (TECO) chemiluminescent NO-NO_2-NO_x analyzer-Series 10 (S/N 10AR-6795-88) was used to analyze the NO cylinder concentrations. The multipoint calibration procedure specified in EPA's Traceability Protocol No. 1 was used to calibrate the TECO analyzer. Two NBS-SRM NO in N_2 cylinders and zero gas (nitrogen) were used to generate calibration concentrations in the range of 0 to 500 ppm. A multipoint calibration (zero level and five upscale concentrations) was performed prior to each set of analyses. The multipoint calibration was accomplished by dilution of the highest NBS-SRM (approximately 2800 ppm) with zero gas (nitrogen) using a dilution system. At the conclusion of the multipoint calibration, a check of the calibration curve was performed using the lower NBS-SRM without

dilution. The response of the instrument based on the original calibration curve (dilution of higher NBS-SRM) was compared to the response to the true concentration of the lower NBS-SRM. If the difference between the apparent concentration (based on dilution of higher NBS-SRM) was less than 3 percent of the concentration of the lower NBS-SRM, then the analyses of audit cylinders provided by EPA could begin. If not, the multipoint calibration was repeated. Agreement to within ± 3 percent between the EPA audit concentration and the measured concentration was required prior to analysis of the commercial cylinders. Zero and span checks were performed during the analysis period, according to EPA Traceability Protocol No. 1, to ensure stable instrument performance.

Audit 5 cylinder gases were analyzed during the period March 26-27, 1981. Because of the large number of cylinders (28) to be analyzed and the relatively high flow rate (2 ft^3/h) required by the analyzer, a GMPS was chosen for span checks rather than an NBS-SRM. Cylinders of NO in N_2 prepared by Scott-Marrin, Inc. for Audit 4 were compared with an appropriate SRM and found to have degraded less than the average 1 percent per month specified in EPA Traceability Protocol No. 1. These cylinders were used as the GMPS in Audit 5.

3.2 ANALYSIS OF SULFUR DIOXIDE CYLINDERS

A TECO pulsed fluorescent SO_2 analyzer-Series 40 (S/N SDM-6997-90) was used to analyze the SO_2 cylinder concentrations. The analyzer was calibrated as described in Section 3.1. NBS-SRMs at 972 ppm and 95.1 ppm were used to provide calibration concentrations by dilution. An NBS-SRM at 45.7 ppm was used without dilution to check the calibration curve. After the multipoint calibration, audit cylinders provided by EPA were analyzed. Agreement to within ± 3 percent between the EPA audit and the measured concentrations was required prior to analysis of the commercial cylinders. Zero (nitrogen) and span checks were performed during the analysis, according to EPA Traceability Protocol No. 1, to ensure stable instrument performance.

Audit 5 cylinder gases were analyzed during the period April 8-14, 1981 (500 ppm) and June 15, 1981 (90 ppm). The delay in analysis of the 90 ppm cylinders of SO_2 resulted from delays in receiving the 45.7 and 95.1 ppm SRMs from NBS. Because of the large number of cylinders (26) to be analyzed and the relatively high flow rate (3 ft^3/h) required by the analyzer, a GMPS was chosen for span checks instead of an NBS-SRM. Cylinders of SO_2 in N_2 prepared by Airco for Audit 4 were compared with an appropriate SRM and found to have degraded less than the average 1 percent per month specified in EPA Traceability Protocol No. 1. These cylinders were used as the GMPS in Audit 5.

3.3 ANALYSIS OF CARBON MONOXIDE CYLINDERS

A Bendix nondispersive infrared analyzer Model 8501-5CA(S/N B04574) was used to analyze CO cylinder concentrations. The analyzer was calibrated as described in Section 3.1, using NBS-SRMs to provide calibration concentrations. After the multipoint calibration, an audit cylinder provided by EPA was analyzed. Agreement to within ± 3 percent between the EPA audit and the measured concentrations was required prior to analysis of the commercial cylinders. Zero (nitrogen) and span checks were performed during the analysis, according to EPA Traceability Protocol No. 1, to ensure stable instrument performance.

Audit 5 cylinder gases were analyzed during the period March 18-19, 1981. Because of the large number of cylinders (28) to be analyzed and the relatively high flow rate (3 ft^3/h) required by the analyzer, a GMPS was chosen for span checks rather than an NBS-SRM. Cylinders of CO in N_2 prepared by Airco were compared to an appropriate NBS-SRM and used as the GMPS in Audit 5.

3.4 EPA QUALITY ASSURANCE PROGRAM

To assess the quality of data obtained during the analysis of commercial cylinders, EPA conducted an external quality assurance program consisting of a performance audit of the analyzers used by RTI to determine cylinder concentrations. EPA provided audit cylinders of NO, CO, and SO_2 in nitrogen to RTI for analysis prior to analysis of Audit 5 cylinder gases. RTI analyzed the EPA audit cylinders, determined the concentration based on the calibration curve of the source analyzers, and reported the data to EPA. If the agreement between the audit cylinder and the measured concentration was within ± 3 percent, RTI proceeded to analyze each commercial gas cylinder. If the measured level exceeded the ± 3 percent limit, then recalibration of the source analyzer and reanalysis of additional audit cylinders were required. The data from the EPA performance audit are shown in Table 4. The agreement between the RTI measured concentrations and the EPA audit concentrations was within ± 3 percent for all cylinders.

In addition to the EPA performance audit, EPA performed a confirmation analysis of any cylinder gas where the percent accuracy between the manufacturer's analysis and the mean of RTI's analysis was greater than ± 4 percent. EPA analysis results are included in Tables 5-7, whenever required by the above criterion.

TABLE 4. EPA PERFORMANCE AUDIT OF RTI

Cylinder no.	Pollutant	RTI analysis date	RTI measured conc. (ppm)	EPA audit conc. (ppm)	Difference RTI-EPA (ppm)	Percent accuracy (%)
FF-100554	CO Bal. N_2	March 19, 1981	479	476	3	0.6
JJ1199	CO Bal. N_2	March 16, 1981	44.7	43.9	0.8	1.8
FF6433	NO Bal. N_2	March 25, 1981	444	449	-5	-1.1
LL4679	NO Bal. N_2	March 25, 1981	50.5	50.7	-0.2	-0.4
JJ1045	SO_2 Bal. N_2	April 7, 1981	574	576	-2	-0.3
JJ1514	SO_2 Bal. N_2	June 10, 1981	93.5	93.2	0.3	0.3

Percent accuracy = 100(RTI - EPA)/EPA.

SECTION 4

RESULTS OF CYLINDER GAS ANALYSES

The results for Audit 5 are given in Tables 5 through 7. Each table includes manufacturer, cylinder type, manufacturer's analysis, mean of RTI analysis, EPA-QAD confirmation analysis (if difference between manufacturer and RTI analyses is $>\pm 4$ percent), ppm difference, and percent accuracy. Table 5 gives the results for sulfur dioxide, Table 6 for nitric oxide, and Table 7 for carbon monoxide.

Audits 3 and 4 included a reanalysis of cylinder gases from the preceding audit. The purpose of this reanalysis was to judge the stability of the gases since the previous analysis. A reanalysis of cylinder gases obtained and analyzed during Audit 4 was not performed during Audit 5, since stability of these gases had been demonstrated in Audits 3 and 4.

TABLE 5. RESULTS OF SULFUR DIOXIDE CYLINDER ANALYSES (AUDIT 5) - April-June 1981

Manufacturer	Cylinder Construction	Manufacturer's Analysis* (ppm)	Mean of RTI Analysis** (ppm)	EPA-QAD Analysis (ppm)	Difference MFG - RTI (ppm)	Percent Accuracy (%)
AGA Burdox, Inc.	Aluminum	525	495	496	30	6.1
	Aluminum	96.0	88.1	87.9	7.9	9.0
Air Monitoring Gas Company			Company does not supply SO_2			
Airco Industrial Gases	Aluminum	494	487	***	7	1.4
	Aluminum	89.0	87.0	***	2	2.3
Air Products & Chemicals, Inc.	Steel	503	527	524	-24	-4.6
	Steel	88.0	129	129	-41	-31.7
Big Three Industries	Aluminum	546	433	438	113	26.1
	Aluminum	97.0	70.1	70.1	26.9	38.4
Ideal Gas Products	Aluminum	500	447	451	53	11.9
	Aluminum	100	94.3	94.6	5.7	6.0
Liquid Carbonic Corp.	Aluminum	492	510	***	-18	-3.5
	Aluminum	91.6	91.8	***	- 0.2	-0.2
Matheson Gas Products	Steel	503	541	537	-38	-7.0
	Steel	98.0	108	108	-10	-9.3
MG Scientific Gas Products	Aluminum	524	367	367	157	42.8
	Aluminum	86.6	40.8	38.6	45.8	112
North East Cryogenics	Aluminum	500	462	466	38	8.2
	Aluminum	100	89.2	89.1	10.8	12.1
Scientific Gas Products, Inc.	Aluminum	530	499	500	31	6.2
	Aluminum	90.0	80.5	79.5	9.5	11.8
Scott Environmental Tech., Inc.	Aluminum	506	508	***	-2	-0.4
	Aluminum	94.2	91.3	***	2.9	3.2
Scott-Marrin Inc.	Aluminum	485	487	***	-2	-0.4
	Aluminum	84.6	84.4	***	0.2	0.2
Linde Div. of Union Carbide	Steel	490	459	466	31	6.8
	Steel	100	168	171	-68	-40.5

* Manufacturer's certified analysis.

** Mean of three analyses.

*** EPA-QAD confirmation analysis not required.

Percent accuracy = 100(Manufacturer - RTI)/RTI.

TABLE 6. RESULTS OF NITRIC OXIDE CYLINDER ANALYSES (AUDIT 5) - April 1981

Manufacturer	Cylinder Construction	Manufacturer's Analysis* (ppm)	Mean of RTI Analysis** (ppm)	EPA-QAD Analysis (ppm)	Difference MFG - RTI (ppm)	Percent Accuracy (%)
AGA Burdox, Inc.	Aluminum	303	305	***	-2	-0.7
	Aluminum	46.8	48.2	***	-1.4	-2.9
Air Monitoring Gas Company	Steel	297	304	***	-7	-2.3
	Steel	51.5	54.8	53.9	-3.3	-6.0
Airco Industrial Gases	Aluminum	299	296	***	3	1.0
	Aluminum	49.2	50.6	***	-1.4	-2.8
Air Products & Chemicals, Inc.	Steel	294	297	***	-3	-1.0
	Steel	50.0	52.3	***	-2.3	-4.4
Big Three Industries	Aluminum	250	263	***	-13	-4.9
	Aluminum	34.0	36.5	37.1	- 2.5	-6.8
Ideal Gas Products	Aluminum	278	277	***	1	0.4
	Aluminum	45.0	45.5	***	-0.5	-1.1
Liquid Carbonic Corp.	Aluminum	278	284	***	-6	-2.0
	Aluminum	48.0	47.2	***	0.8	1.7
Matheson Gas Products	Steel	295	297	***	-2	-0.7
	Aluminum	45.0	46.4	***	-1.4	-3.0
MG Scientific Gas Products	Aluminum	292	270	276	22	8.1
	Aluminum	57.0	47.5	47.3	9.5	20.0
North East Cryogenics	Aluminum	278	279	***	-1	-0.4
	Aluminum	45.0	44.3	***	0.7	1.6
Scientific Gas Products, Inc.	Aluminum	294	298	***	-4	- 1.3
	Aluminum	41.0	46.3	48.3	-5.3	-11.4
Scott Environmental Tech., Inc.	Aluminum	314	315	***	-1	-0.3
	Aluminum	53.0	53.6	***	-0.6	-1.1
Scott-Marrin, Inc.	Aluminum	294	291	***	3	1.0
	Aluminum	48.7	49.2	***	-0.5	-1.0
Linde Div. of Union Carbide	Steel	315	313	***	2	0.6
	Steel	530****	514	***	16	3.1

* Manufacturer's certified analysis.

Percent Accuracy = 100(Manufacturer - RTI)/RTI.

** Mean of three analyses.

*** EPA-QAD confirmation analysis not required.

****Nominal 50 ppm ordered but 530 ppm shipped.

TABLE 7. RESULTS OF CARBON MONOXIDE CYLINDER ANALYSES (AUDIT 5) - April 1981

Manufacturer	Cylinder Construction	Manufacturer's Analysis* (ppm)	Mean of RTI Analysis** (ppm)	EPA-QAD Analysis (ppm)	Difference MFG - RTI (ppm)	Percent Accuracy (%)
AGA Burdox, Inc.	Aluminum	488	495	***	- 7	-1.4
	Aluminum	50.9	52.1	***	- 1.2	-2.3
Air Monitoring Gas Company	Steel	495	493	***	2	0.4
	Steel	50.0	46.2	46.6	3.8	8.2
Airco Industrial Gases	Aluminum	451	449	***	2	0.4
	Aluminum	47.0	45.2	45.5	1.8	4.0
Air Products & Chemicals, Inc.	Steel	427	491	488	-64	-13.0
	Steel	44.4	52.8	52.9	- 8.4	-15.9
Big Three Industries	Steel	529	532	***	-3	-0.6
	Steel	53	53.0	***	0.0	0.0
Ideal Gas Products	Aluminum	504	489	***	15	3.1
	Aluminum	50.5	50.3	***	0.2	0.4
Liquid Carbonic Corp.	Aluminum	492	489	***	3	0.6
	Aluminum	49.1	49.0	***	0.1	0.2
Matheson Gas Products	Aluminum	507	586	575	-79	-13.5
	Aluminum	56	59.9	61.1	- 3.9	- 6.5
MG Scientific Gas Products	Aluminum	457	453	***	4	0.8
	Aluminum	47.1	50.5	50.7	-3.4	-6.7
North East Cryogenics	Aluminum	501	485	***	16	3.3
	Aluminum	49.3	49.8	***	-0.5	-1.0
Scientific Gas Products, Inc.	Aluminum	500	495	***	5	1.0
	Aluminum	42.0	50.2	50.4	-8.2	-16.3
Scott Environmental Tech., Inc.	Aluminum	505	504	***	1	0.2
	Aluminum	50.0	49.6	***	0.4	0.8
Scott-Marrin, Inc.	Aluminum	496	499	***	-3	-0.6
	Aluminum	51	51.0	***	0.0	0.0
Linde Div. of Union Carbide	Steel	500	484	***	16	3.3
	Steel	50	49.1	***	0.9	1.8

* Manufacturer's certified analysis.

** Mean of three analyses.

*** EPA-QAD confirmation analysis not required.

Percent accuracy = 100(Manufacturer - RTI)/RTI.

SECTION 5

SUMMARY OF RESULTS OF AUDITS 1 THROUGH 5

The results for Audits 1 through 5 of commercial cylinder gases are summarized in Tables 8, 9, and 10. Table 8 gives the results for sulfur dioxide, Table 9 for nitric oxide, and Table 10 for carbon monoxide.

TABLE 8. SUMMARY OF RESULTS FOR AUDITS 1 THROUGH 5 OF COMMERCIAL CYLINDERS FOR SULFUR DIOXIDE

Manufacturer	Cylinder Construction	Nominal Conc. (ppm)	Percent Accuracy Audit 1 (June 78)	Audit 2 (Jan.79)	Audit 3 (Sept.79)	Audit 4 (Apr.80)	Audit 5 (May 81)
AGA Burdox, Inc.	Aluminum	500	*	*	*	*	6.1
	Aluminum	90	*	*	*	*	9.0
Air Monitoring Gas Company	Company does not supply SO_2						
Airco Industrial Gases	Aluminum	500	*	-0.6	-0.8	-1.9	1.4
	Aluminum	90				6.5	2.3
Air Products & Chemicals, Inc.	Steel	500	9.0	2.6	1.0	-0.2	- 4.6
	Steel	90				18.8	-31.7
Big Three Industries	Steel	500	7.5	1.4		-6.1	
	Aluminum	500			-5.5		26.1
	Steel	90				-1.2	
	Aluminum	90					38.4
Ideal Gas Products	Steel	500	4.0	2.9	-8.8		
	Aluminum	500				-21.0	11.9
	Steel	90	-8.0	-35.7	-7.0		
	Aluminum	90				-25.0	6.0
Liquid Carbonic Corp.	Steel	500	2.1				
	Aluminum	500		-0.8	-1.0	4.3	-3.5
	Aluminum	90				-7.5	-0.2
Matheson Gas Products	Steel	500	*	-0.8			-7.0
	Aluminum	500			-0.4	-0.2	
	Aluminum	90				-6.1	
	Steel	90					-9.3
MG Scientific Gas Products	Aluminum	500	-7.2	1.4	-0.8		42.8
	Steel	500				9.1	
	Aluminum	90	-9.4		-3.3		112
	Steel	90				12.2	
North East Cryogenics	Aluminum	500					8.2
	Steel	500	14.7	-12.5			
	Steel	90	-10.1	-15.6			
	Steel	500	- 4.8(1)		- 3.8	-20.0	
	Steel	500	- 1.0(1)				
	Steel	90	-19.7(1)		-21.6	-35.0	
	Aluminum	90					12.1
Scientific Gas Products, Inc.	Steel	500	-2.4		-12.2		
	Aluminum	500		-2.2		-0.8	6.2
	Steel	90			- 3.0		
	Aluminum	90				-9.5	11.8
Scott Environmental Tech., Inc.	Aluminum	500	- 1.6	-0.8	1.7	0.6	-0.4
	Aluminum	90	-11.3	-3.1	3.2	-1.7	3.2
Scott-Marrin, Inc.	Aluminum	500	0.2	-0.6	0.2	-1.0	-0.4
	Aluminum	90				0.4	0.2
Linde Div. of Union Carbide	Steel	500	5.8	-4.6	8.9	3.2	6.8
	Steel	90	2.2	-2.5	-3.8	13.3	-40.5

* Company not included in audit.

1 These cylinders were not part of the first audit but were procured and analyzed after reviewing the results of the first audit.

Percent accuracy = 100(Manufacturer - RTI)/RTI.

TABLE 9. SUMMARY OF RESULTS FOR AUDITS 1 THROUGH 5 OF COMMERCIAL CYLINDERS FOR NITRIC OXIDE

Manufacturer	Cylinder Construction	Nominal Conc. (ppm)	Percent Accuracy Audit 1 (June 78)	Audit 2 (Jan.79)	Audit 3 (Sept.79)	Audit 4 (Apr.80)	Audit 5 (Apr.81)
AGA Burdox	Aluminum	300	*	*	*	*	-0.7
	Aluminum	50	*	*	*	*	-2.9
Air Monitoring Gas Company	Steel	300	*	*	*	*	-2.3
	Steel	50	*	*	*	*	-6.0
Airco Industrial Gases	Aluminum	300	*	2.0	3.5	0	1.0
	Aluminum	50				-0.8	-2.8
Air Products & Chemicals, Inc.	Steel	300	2.2	0.2	5.6	3.4	-1.0
	Steel	50				-2.7	-4.4
Big Three Industries	Steel	300	11.1	-2.0			
	Aluminum	300			-6.3	-2.3	-4.9
	Aluminum	50				-3.3	-6.8
Ideal Gas Products	Steel	300	>100**	11.8	3.1		
	Aluminum	300	>100**			1.3	0.4
	Steel	50	-0.7(1)	-12.9	4.7		
	Aluminum	50	4.0(1)			0.2	-1.1
Liquid Carbonic Corp.	Steel	300	-2.0				
	Aluminum	300		-2.0	-3.4	2.2	-2.0
	Aluminum	50				1.5	1.7
Matheson Gas Products	Steel	300	*	2.2			-0.7
	Aluminum	300			-12.4	2.3	
	Aluminum	50				-1.8	-3.0
MG Scientific Gas Products	Aluminum	300					8.1
	Steel	300	-4.8	-5.2	5.7	10.0	
	Steel	50			22.2	21.4	
	Aluminum	50					20.0
North East Cryogenics	Aluminum	300					-0.4
	Steel	300	>100**	7.6	4.0	4.2	
	Steel	50	>100**	53.8	>100**	7.4	
	Steel	300	-0.7(1)				
	Steel	50	4.0(1)				
	Aluminum	50					1.6
Scientific Gas Products, Inc.	Steel	300	-2.0	-2.8	0		
	Aluminum	300				0	- 1.3
	Steel	50			0		
	Aluminum	50				-0.2	-11.4
Scott Environmental Tech., Inc.	Aluminum	300	0.0	0.3	-1.0	1.1	-0.3
	Aluminum	50	0.2	2.8	-2.8	-3.3	-1.1
Scott-Marrin, Inc.	Aluminum	300	2.3	1.0	- 0.6	0	1.0
	Aluminum	50				- 0.2	- 1.0
Linde Div. of Union Carbide	Steel	300	2.3	3.4	8.3	- 2.8	0.6
	Steel	50	0.8	0.4		- 2.0	
	Steel	500			- 1.6		
	Steel	500***					3.1

* Company not included in audit survey.

** Actual percent accuracy not calculated but was greater than 100%.

*** Nominal 50 ppm ordered but 530 ppm shipped.

(1) These cylinders were not part of the first audit but were procured and analyzed after reviewing the results of the first audit.

Percent accuracy = 100(Manufacturer - RTI)/RTI.

TABLE 10. SUMMARY OF RESULTS FOR AUDITS 1 THROUGH 5 OF COMMERCIAL CYLINDERS FOR CARBON MONOXIDE

Manufacturer	Cylinder Construction	Nominal Conc. (ppm)	Percent Accuracy Audit 1 (June 78)	Audit 2 (Jan.79)	Audit 3 (Sept.79)	Audit 4 (Apr.80)	Audit 5 (Apr.81)
AGA Burdox	Aluminum	500	*	*	*	*	- 1.4
	Aluminum	50	*	*	*	*	- 2.3
Air Monitoring Gas Company	Steel	300	*	*	*	*	0.4
	Steel	50	*	*	*	*	8.2
Airco Industrial Gases	Aluminum	500			3.3	1.6	0.4
	Aluminum	50	*	*		- 0.4	4.0
Air Products & Chemicals, Inc.	Steel	500			1.9	- 0.5	-13.0
	Steel	50	*	*		0.6	-15.9
Big Three Industries	Aluminum	500			- 3.5		
	Steel	500	*	*		1.4	- 0.6
	Steel	50				14.1	0.0
Ideal Gas Products	Aluminum	500					3.1
	Steel	500			9.2	0.4	
	Steel	50	*	*	- 1.2	-14.6	
	Aluminum	50					0.4
Liquid Carbonic Corp.	Aluminum	500			- 1.1	- 0.2	0.6
	Aluminum	50	*	*		- 0.6	0.2
Matheson Gas Products	Aluminum	500			- 1.1	11.3	-13.5
	Aluminum	50	*	*		- 3.3	- 6.5
MG Scientific Gas Products	Aluminum	500					0.8
	Steel	500			- 7.5	3.3	
	Steel	50	*	*	7.9	- 3.5	
	Aluminum	50					- 6.7
North East Cryogenics	Aluminum	500					3.3
	Steel	500			- 1.5	0.2	
	Steel	50	*	*	- 3.9	-12.8	
	Aluminum	50					- 1.0
Scientific Gas Products, Inc.	Steel	500			2.6		
	Aluminum	500				2.6	1.0
	Steel	50	*	*	0.2		
	Aluminum	50				- 2.3	-16.3
Scott Environmental Tech., Inc.	Aluminum	500			1.2	0.6	0.2
	Aluminum	50	*	*	- 3.3	- 1.1	0.8
Scott-Marrin, Inc.	Aluminum	500			2.8	1.0	- 0.6
	Aluminum	50	*	*		- 1.0	0.0
Linde Div. of Union Carbide	Steel	500			1.6	0.8	3.3
	Steel	50	*	*	17.8	6.8	1.8

* Carbon monoxide was not included in Audits 1 and 2.

Percent accuracy = 100(Manufacturer - RTI)/RTI.

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Definitive SOx Control Process Evaluations Aqueous Carbonate and Wellman-Lord (Acid, Allied Chemical, and Resox) FGD (Flue Gas Desulfurization) Technologies

Tennessee Valley Authority
Muscle Shoals, AL

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

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Interagency Energy/Environment R&D Program Report

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16. ABSTRACT The report gives results of economic evaluations of two processes: the Rockwell International aqueous carbonate process (ACP) and the Wellman-Lord process, the latter applied to a sulfuric acid plant, the Foster Wheeler Resox process, and the Allied Chemical coal reduction process, all for sulfur production. The ACP uses a spray dryer flue gas desulfurization (FGD) system and molten salt reduction with coal to make sulfur. For a 500-MW power plant burning 3.5% sulfur coal, capital investments for the ACP and the Wellman-Lord (acid, Resox, and Allied) processes are $119, $131, $138, and $141/kW, respectively. Annual revenue requirements are 4.81, 5.11, 6.03, and 5.94 mills/kWh, respectively. The ACP has a major cost advantage because it incorporates final fly ash and chloride removal as process functions. Fly ash removal credits and Wellman-Lord chloride control costs essentially determine the capital investment relationships of the processes. The ACP has a major advantage in annual revenue requirements because it does not need process or reheat steam. Wellman-Lord process costs are the same for all three applications. The cost difference results from end plant costs to produce acid or sulfur. The cost relationship could be affected by further development. The ACP, Resox, and Allied processes have not been operated as commercial FGD systems.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Coal	Pollution Control	13B	08G
Sulfur Oxides	Fly Ash	Stationary Sources	07B	
Flue Gases	Chlorides	Aqueous Carbonate	21B	
Desulfurization		Wellman-Lord	07A,07D	
Sulfuric Acid		Allied Chemical		
Sulfur		Resox		
		Coal Reduction		

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ABSTRACT

Economic evaluations were made of the Rockwell International aqueous carbonate process (ACP) and versions of the Wellman-Lord process incorporating a sulfuric acid plant and the Foster Wheeler Resox® and Allied Chemical coal reduction processes for sulfur production. The ACP uses a spray dryer flue gas desulfurization (FGD) system and molten salt reduction with coal to make sulfur. For a 500-MW power plant burning 3.5% sulfur coal capital investments for the ACP and the Wellman-Lord acid, Resox, and Allied processes are 119, 131, 138, and 141 $/kW respectively. Annual revenue requirements are 4.81, 5.11, 6.03, and 5.94 mills/kWh respectively. The ACP has a major cost advantage because it incorporates final fly ash and chloride removal as process functions. Fly ash removal credits and Wellman-Lord chloride control costs essentially determine the capital investment relationships of the processes. The ACP has a major advantage in annual revenue requirements because it does not need process or reheat steam. Wellman-Lord process costs are the same for all three versions. The cost differences result from end plant costs to produce acid or sulfur. The cost relationship could be affected by further development. The ACP, Resox, and Allied processes have not been operated as commercial FGD systems.

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ABBREVIATIONS AND CONVERSION FACTORS

ABBREVIATIONS

ac	acre
aft^3/min	actual cubic feet per minute
bbl	barrel
Btu	British thermal unit
^oF	degrees Fahrenheit
dia	diameter
FGD	flue gas desulfurization
ft	feet
ft^2	square feet
ft^3	cubic feet
gal	gallon
gpm	gallons per minute
gr	grain
hp	horsepower
hr	hour
in.	inch
k	thousand
kW	kilowatt
kWh	kilowatthour
lb	pound
L/G	liquid-to-gas ratio in gallons per thousand actual cubic feet of gas at outlet conditions
M	million
mi	mile
mo	month
MW	megawatt
ppm	parts per million
psig	pounds per square inch (gauge)
rpm	revolutions per minute
sec	second
sft^3/min	standard cubic feet per minute (60^oF)
SS	stainless steel
yr	year

CONVERSION FACTORS

EPA policy is to express all measurements in Agency documents in metric units. Values in this report are given in British units for the convenience of engineers and other scientists accustomed to using the British systems. The following conversion factors may be used to provide metric equivalents.

British			Metric	
ac	acre	0.405	hectare	ha
bbl	barrels of oil[a]	158.97	liters	L
Btu	British thermal unit	0.252	kilocalories	kcal
°F	degrees Fahrenheit minus 32	0.5556	degrees Celsius	°C
ft	feet	30.48	centimeters	cm
ft^2	square feet	0.0929	square meters	m^2
ft^3	cubic feet	0.02832	cubic meters	m^3
ft/min	feet per minute	0.508	centimeters per second	cm/s
ft^3/min	cubic feet per minute	0.000472	cubic meters per second	m^3/s
gal	gallons (U.S.)	3.785	liters	L
gpm	gallons per minute	0.06308	liters per second	L/s
gr	grains	0.0648	grams	g
gr/ft^3	grains per cubic foot	2.288	grams per cubic meter	g/m^3
hp	horsepower	0.746	kilowatts	kW
in.	inches	2.54	centimeters	cm
lb	pounds	0.4536	kilograms	kg
lb/ft^3	pounds per cubic foot	16.02	kilograms per cubic meter	kg/m^3
lb/hr	pounds per hour	0.126	grams per second	g/s
psi	pounds per square inch	6895	pascals (newton per square meter)	Pa (N/m^2)
mi	miles	1609	meters	m
rpm	revolutions per minute	0.1047	radians per second	rad/s
sft^3/min	standard cubic feet per minute (60°F)	1.6077	normal cubic meters per hour (0°C)	m^3/h
ton	tons (short)[b]	0.9072	metric tons	tonne
ton, long	tons (long)[b]	1.016	metric tons	tonne
ton/hr	tons per hour	0.252	kilograms per second	kg/s

a. Forty-two U.S. gallons per barrel of oil.
b. All tons, including tons of sulfur, are expressed in short tons in this report.

DEFINITIVE SO_x CONTROL PROCESS EVALUATIONS:

AQUEOUS CARBONATE AND WELLMAN-LORD

(ACID, ALLIED CHEMICAL, AND RESOX®)

FGD TECHNOLOGIES

EXECUTIVE SUMMARY

INTRODUCTION

For more than a decade, the Tennessee Valley Authority (TVA) has conducted a program of systematic analysis of the economics of electric utility flue gas desulfurization (FGD) processes and related technology. Many of these studies have been sponsored by the U.S. Environmental Protection Agency (EPA) as part of their FGD research and development program. The analyses are based as closely as possible on current U.S. utility power plant conditions in which FGD is likely to find the widest and most useful application and conform to a consistent basis of analysis so that comparisons among processes will be equitable and generally applicable.

The basis of the analyses is a conceptual design of the process for a 500-MW power unit at a midwestern coal-fired power plant. Case variations assess the effects of power unit size and fuel conditions, FGD requirements, and other conditions likely to affect FGD costs. The FGD economics, based on regulated utility economics, are developed for both capital investment to construct the FGD system and revenue requirements for its operation.

This study is the third of a series begun in 1977 to evaluate recent trends in FGD technology and energy use. In addition to updating the Wellman-Lord process evaluation, it deals with two emerging technologies, dry FGD processes using spray dryers and processes that produce sulfur from concentrated SO_2 using coal as the reducing agent.

PROCESS BACKGROUND AND DESCRIPTION

The Rockwell International aqueous carbonate process (ACP) combines both spray dryer FGD and coal reduction to produce elemental sulfur. As in the earlier study, the Wellman-Lord process is used to produce SO_2 that is processed to sulfuric acid or elemental sulfur. This study incorporates numerous technical changes made in the Wellman-Lord process

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during the past few years. Both the Resox® process, under development by the Foster Wheeler Energy Corporation, and the Allied Chemical coal/SO_2 reduction process, being developed by the Allied Chemical Corporation, are end plants that process the off-gas of an FGD system to sulfur. A sulfuric acid producing version of the process is included for comparison.

The processes differ considerably in stage of development. The Wellman-Lord process is in commercial FGD use. Sulfuric acid plants and the Claus process used in the ACP and Allied unit are standard industrial technology. The spray dryer portion of the ACP has had considerable pilot-scale development but the recovery process has not yet been evaluated as part of an FGD system. The Resox and Allied processes have been developed on a pilot scale and the Resox unit has been operated as part of an FGD demonstration system.

Aqueous Carbonate Process

Dry absorption FGD, in which the reaction products are collected as dry particulate matter, has the potential of reducing or eliminating several disadvantages of wet scrubbing FGD. Corrosion and scaling associated with wet scrubbing and saturated flue gas are greatly reduced or eliminated; flue gas pressure drops are reduced and handling and processing of large volumes of liquid are eliminated; little or no flue gas reheating is required. In addition, integration of fly ash removal with the FGD system is easier. The high removal efficiencies and absorbent utilization rates of wet scrubbing are, however, difficult or impossible to attain under some conditions, particularly if the absorbent is injected as a powder. Introduction of the absorbent in a limited quantity of liquid using a spray dryer increases removal efficiency by improving dispersion and allowing limited liquid phase reaction. Most of the advantages of dry injection are retained since the liquid evaporates in the spray dryer, producing particulate matter and leaving the flue gas unsaturated.

The use of a highly reactive absorbent is important in dry absorption FGD. Sodium-based absorbents are thus particularly attractive for dry absorption FGD use. Soda ash is presently the most practical spray dryer absorbent because it is a generally available industrial chemical and less expensive than other suitable sodium compounds. Its cost, however, makes recovery of the absorbent desirable in a generally applicable FGD process, as it does in wet scrubbing processes. The most direct route involves reduction to Na_2S followed by carbonation to produce Na_2CO_3 and H_2S. The salts are reduced in molten form because they melt before efficient reaction temperatures are reached. The procedures are well developed pulp and paper technology.

Rockwell International began studies of spray dryer FGD and molten salt reduction of sodium sulfur salts in the early 1970's. The spray dryer studies evolved into a waste-producing spray dryer FGD process that has had extensive pilot-scale evaluation. Several full-sized units

are being constructed. The same spray dryer technology is used in the ACP. The reduction and regeneration portions of the ACP have not been integrated with the spray dryer portion of the process in an operating FGD system; however, a demonstration-sized system is under construction.

A flow diagram for the ACP is shown in Figure S-1. Mechanical collectors situated upstream from the power plant ID fans remove 85% of the fly ash. The flue gas then enters the FGD plenum and is distributed to the spray dryer - ESP trains. The flue gas enters at the top of the cylindrical spray dryer and passes downward through an atomized solution of Na_2CO_3 produced by three rotary-disk atomizers. The solution is evaporated in the dryer, forming particles of Na_2SO_3, some Na_2SO_4, and unreacted Na_2CO_3 that are carried out through the conical bottom and removed, with the remaining fly ash, in an ESP. The flue gas is cooled to only 170°F and thus requires no reheating.

The particulate matter is pneumatically conveyed to storage bins from which it is withdrawn, blended with finely ground power plant coal in metered quantities, and pneumatically injected into the bottoms of the reduction reactors. Each reactor is a refractory-lined vessel that operates about one-half full of molten salt. Preheated air is also blown into the bottom of the reactor to maintain the temperature at 1800°F by oxidation of some of the coal. The reduced salt, primarily Na_2S, overflows from the middle of the reactor and is quenched and dissolved. The off-gas is cleaned by scrubbing with water for use in the regeneration process as a CO_2 source. Since an appreciable quantity of chlorides are vaporized in the reactors, the cleaning process also serves as a chloride purge to control the level of chlorides in the regeneration system.

The salt solution is treated in a series of liquid-phase, unheated reactions, first in a precarbonator with recycled H_2S to produce NaHS, and then with off-gas and recycled CO_2 in a crystallizer and carbonator to produce $NaHCO_3$ and H_2S. The precarbonator contains a filter loop to remove residual fly ash and reducer ash. Part of the H_2S stream is recycled to the precarbonator; the remainder is processed to sulfur in a conventional Claus unit. The $NaHCO_3$ is heated in a decomposer with steam generated by the reactor off-gas coolers to produce CO_2, which is recycled to the carbonator, and Na_2CO_3, which is reused in the spray dryers.

Claus Unit

The Claus process is widely used for the catalytic vapor-stage oxidation of H_2S to sulfur. The feed stream is partially oxidized to SO_2 at about 2000°F, directly forming a considerable percentage of sulfur. The gas is cooled in steam boilers to condense and remove the sulfur, then reheated to 450°F to 500°F and passed through a bed of catalyst such as alumina where the H_2S and SO_2 react to form sulfur and H_2O. The off-gas is then cooled to 300°F in a steam boiler to remove the sulfur. The gas is then passed through a second catalytic converter. Two-stage conversion usually results in a total conversion of about 90%.

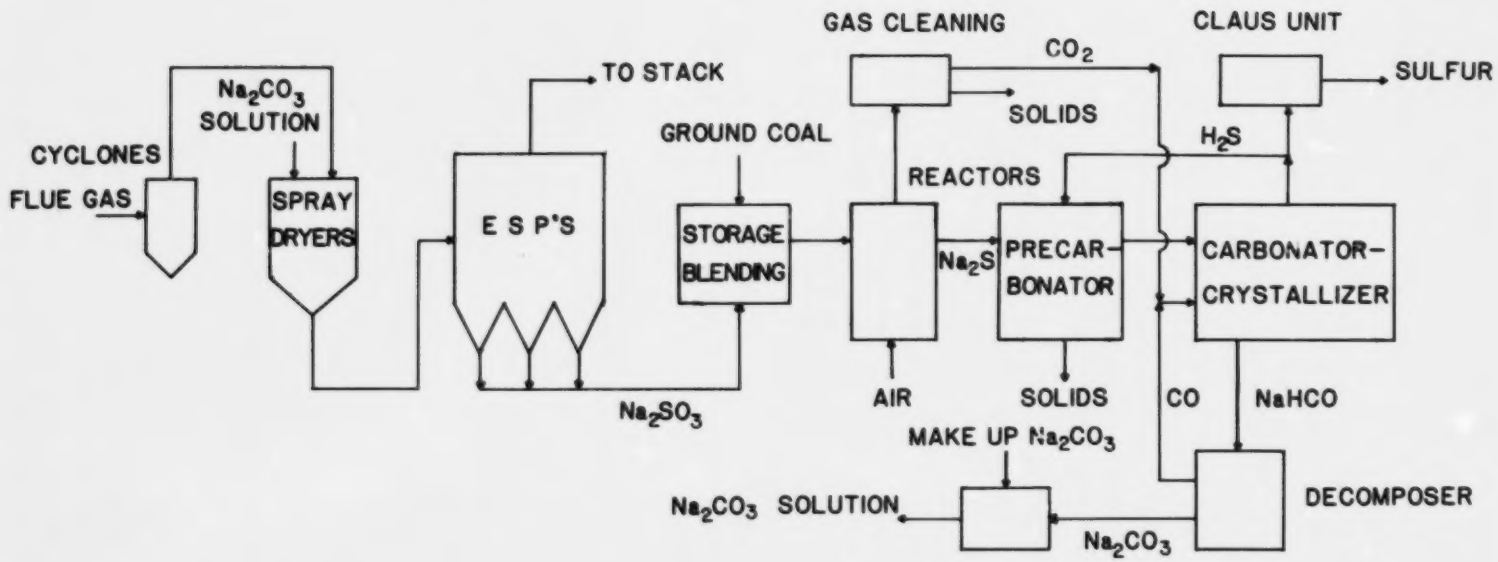

Figure S-1. Aqueous carbonate process.

In FGD applications some variations from conventional Claus plant design are possible. In the Allied process the feed gas contains both SO_2 and H_2S and partial oxidation is not necessary. Additional converters and tail-gas emission control are also not necessary for the ACP and Allied processes because the tail gas can be returned to the FGD system.

Wellman-Lord

In addition to dry absorption methods described above, flue gas SO_2 can be removed and later regenerated (as a concentrated off-gas) in a sodium-based wet scrubbing processes in which the absorption reaction produces $NaHSO_3$. The $NaHSO_3$ can then be thermally decomposed to Na_2SO_3 and SO_2. The SO_2 can, by careful control of process conditions, be either directly reduced to sulfur or converted to sulfuric acid. The Wellman-Lord process included in this study is a wet scrubbing process that uses a solution of Na_2SO_3, formed by addition of soda ash to the scrubbing liquid, as the absorbent. The absorbent is regenerated and SO_2 is produced by heating it under vacuum in evaporators. Chloride removal upstream of the FGD system is required in most applications to prevent accumulation of corrosive chlorides in the scrubber liquid. In addition removal of the sulfates which are formed by the oxidation of sodium sulfite and also tend to accumulate in the scrubber liquid is required.

The concentrated SO_2 off-gas can be used to produce sulfuric acid in a conventional sulfuric acid unit or it can be reduced to sulfur. For sulfuric acid production a single-contact, single-absorption acid plant of conventional commercial design can be used. In the three commercial utility applications of the process in the United States, the SO_2 is reduced to sulfur by the Allied Chemical methane (natural-gas) reduction process. Processes using coal, a more desirable reducing agent because of its price and availability, are not in large-scale FGD use but the Resox process and the Allied Chemical coal/SO_2 reduction process have been evaluated on a pilot-plant, prototype, or smaller scale.

The Wellman-Lord process, shown in Figure S-2, with the Resox and Allied units, is similar for all three versions. Minor changes in flue gas quantities, because of different quantities of tail gas returned from the byproduct manufacturing area, and in off-gas composition, because of different requirements in the byproduct manufacturing area, are the only modifications. Neither has an appreciable effect on overall design.

For the Wellman-Lord process, fly ash is first removed by the power plant ESP's. The flue gas then enters the FGD system plenum and is distributed to the absorber trains. Each train consists of a prescrubber for chloride control, a cast concrete absorber containing three valve trays and two chimney trays, a mist eliminator, a reheater, and an ID booster fan. The scrubbing solution flows countercurrently through the absorber without overall recycling although it is recirculated independently in each valve tray. The SO_2 in the flue gas reacts with the Na_2SO_3 solution to form $NaHSO_3$ and a small amount of Na_2SO_4.

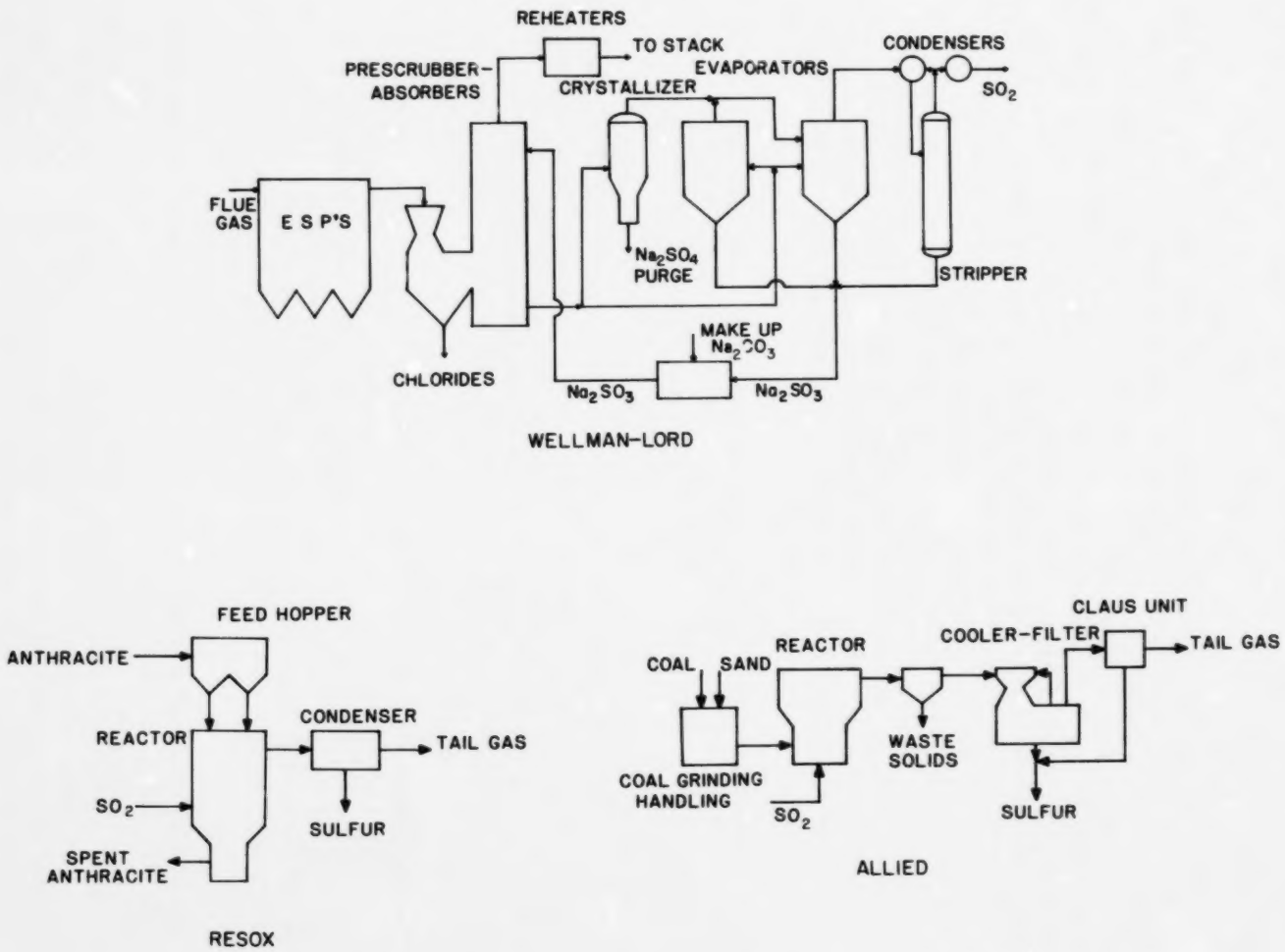

Figure S-2. Wellman-Lord, Resox, and Allied processes.

A portion of the absorber effluent is concentrated by evaporation to selectively crystallize Na_2SO_4, which is dried and stored as a by-product. The evaporator effluent is recombined with the main absorber effluent stream and they are heated to decompose the $NaHSO_3$ to Na_2SO_3 and SO_2. Two trains of double-effect evaporators are used. The first-effect evaporators are steam heated to 205°F at 10 psia; the second-effect evaporators are heated by first-effect vapor to 170°F at 4.5 psia. The uncondensed vapors from the second-effect evaporator heaters and the second-effect evaporator vapors are passed through two-stage condensers to reduce the H_2O content. The condensate is combined with the second-effect evaporator heater condensate and they are steam-stripped to remove SO_2. The stripper overhead is returned to the second-effect condensers. Further H_2O is removed by compressing the vapor from the second-effect condensers. The final SO_2 content of the off-gas is controlled by the condenser design and operating conditions to meet the byproduct manufacturing area requirements.

A purge stream is removed from the first-effect evaporator bottoms to control $Na_2S_2O_3$ and combined with the Na_2SO_4 stream to the dryer. The evaporator bottoms, primarily Na_2SO_3, are then combined and returned to the absorbent preparation area. Sodium losses are replenished by addition of Na_2CO_3 to the scrubbing solution.

Sulfuric Acid Unit

A standard single-contact, single-absorption, 98% efficient acid unit is used. Feed gas from the Wellman-Lord system contains 64 mole % SO_2. The tail gas is returned to the flue gas ducts upstream from the Wellman-Lord system.

Resox Unit

The Resox process, developed by Foster Wheeler Energy Corporation, is based on the direct reduction of SO_2 by anthracite. The reactor requires an $H_2O:SO_2$ molar ratio of 2:1 to 3:1 and careful control of conditions to minimize formation of H_2S. Anthracite is used because a nonagglomerating coal is required.

The Resox unit contains three reactor modules, each containing four reactor sections. The modules are refractory-lined carbon steel vessels without internal compartmentalization. The individual reactors are formed by four individual anthracite feed tubes and four discharge hoppers on each module. Anthracite is conveyed to hoppers above each feed tube and fills the reactor. Spent anthracite is withdrawn from the discharge hoppers at a controlled rate to provide approximately 2 moles of carbon per mole of SO_2. The anthracite in the feed tubes and discharge hoppers serves as a gas seal.

The feed gas from the Wellman-Lord system contains 40 mole % SO_2 and 60 mole % H_2O. The remaining H_2O to achieve the 2:1 H_2O to SO_2 ratio for optimum conversion is provided by the incinerator gas, anthracite moisture, and the combustion of anthracite. A small amount of air is

added to maintain the reactor temperature and the gas is heated to 750°F by injection of incinerator gas. The gas is then injected into the reactors through a manifold system near the vertical midpoint and flows upward, rising to a temperature of about 1300°F in the main reaction zone. Most of the SO_2 is reduced to sulfur vapor. The off-gas contains 8% to 10% S_2. The remainder is H_2O, CO_2, N_2, and small amounts of SO_2, H_2S, and other sulfur compounds. It leaves the reactor at about 700°F and passes through a shell and tube heat exchanger where the sulfur is condensed and removed. The remaining gas is incinerated to convert the sulfur compounds to SO_2 and returned to the flue gas ducts upstream from the Wellman-Lord system.

Allied Unit

The Allied unit has coal grinding and drying equipment and handling equipment to blend it with a small amount of makeup silica sand to form the reducing medium. The type of coal and the SO_2:H_2O ratio are not critical. Power plant coal is ground and dried in an impact mill in an inert gas atmosphere and collected in a cyclone collector followed by a bag filter. Some of the wet inert gas is vented and the rest is dried for reuse and for blanketing in the storage and feed system. The ground coal is conveyed from a storage bin to consecutive reactor feed hoppers isolated by gas locks so that the reactor can be charged at the 24 psia reactor pressure. From the second lock hopper the coal-sand mixture is fed to the reactor by screw conveyor. The coal rate is controlled to provide a 1.3:1.1:1.0 ratio of C:H_2:SO_2.

A single refractory-lined reactor is used. A small amount of air to maintain the reactor temperature at 1500°F to 1800°F is mixed with the 85 mole % SO_2 feed gas from the Wellman-Lord system and injected into the bottom of the reactor. The gas fluidizes the coal-sand mixture and rises to 1500°F to 1800°F as it flows through the bed. The portion of the reactor above the bed is enlarged to reduce particulate matter carryover and increase the reaction time. Most of the particulate matter in the gas leaving the reactor is removed in a cyclone separator. The gas consists of about 15% S_2, 7% H_2S, 55% CO_2, H_2O, N_2, and minor amounts of other sulfur compounds.

The gas is scrubbed with liquid sulfur in a venturi scrubber to condense the sulfur vapor and remove particulate matter. The gas is then passed through a Claus unit to convert the H_2S to sulfur. The Claus unit tail gas is incinerated and returned to the flue gas ducts upstream from the Wellman-Lord system. A portion of the liquid sulfur from the sulfur scrubber is cooled and used in the scrubber. The remainder is filtered, combined with the Claus unit sulfur, and pumped to storage.

PREMISES

These processes are evaluated on the same set of design and economic premises used in the two earlier studies of this series.

Design Premises

The base case is a new 500-MW frontal-fired power unit burning 10,500 Btu/lb pulverized coal containing 3.5% sulfur and 16% ash. It is assumed that 95% of the sulfur is emitted as SO_x (99% SO_2) and 80% of the ash is emitted as fly ash. Emission control facilities are designed to meet the 1971 new-source performance standards (NSPS) of 1.2 lb of SO_2 and 0.1 lb of particulate matter per MBtu of heat input. [The revised NSPS (1979) were promulgated after this study was initiated and underway; impacts of the revised NSPS are therefore not included in this report.] The power unit is assumed to have a 30-year, 127,500-hour life and to operate 7,000 hours the first year. Power unit case variations consist of new and existing (20-year life) 200-MW units, an existing (25-year life) 500-MW unit, new and existing (25-year life) 1,000-MW units, 2% and 5% sulfur coal, and an existing (25-year life) 500-MW unit fired with 2.5% sulfur oil.

FGD system design is based on vendor information and appropriate industry design practice. The system begins with a plenum downstream from the power unit ID fans and ends with ducting to the stack plenum. Two absorber trains are used for 200-MW units and four trains for 500- and 1000-MW units. No spares or bypasses are used. For the ACP, mechanical fly ash collectors upstream from the power unit ID fans are also included. Each ACP absorber train consists of a mechanical collector, a spray dryer, an ESP, and an ID booster fan. Each Wellman-Lord absorber train consists of a FD booster fan, a chloride prescrubber, an SO_2 absorber, and a flue gas reheater. The regeneration systems are generally single-train designs except for some subsystems. FGD case variations consist of wet-scrubbing fly ash removal, 90% SO_2 removal, and Resox and Allied units sized for the same quantities of sulfur production at 90% of the design conversion efficiencies. [Since neither of these processes represent proven technologies, this case will show the effect on the process economics if the Resox or Allied units achieve only 90% of the design conversion of SO_2 to sulfur.]

Fly ash removal costs are not included in the base-case Wellman-Lord process FGD costs. Since ESP's are an inherent part of the ACP, a credit is applied to the ACP costs for new plants because separate ESP's for fly ash removal are unnecessary. For existing plants it is assumed that the ESP's are already installed and only ESP operating costs are credited.

Economic Premises

The economic premises provide for determination of the capital investment for installation of the FGD system and revenue requirements

for its operation. The premises are based on a regulated utility with a 60% debt, 40% equity capital structure. Costs are based on vendor information, TVA data, and published information.

Capital investment costs consist of direct costs, indirect costs, land, and working capital. The costs are projected to mid-1979, representing a mid-1977 to mid-1980 construction period with a 50% expenditure by mid-1979. Direct capital costs cover process equipment, piping and insulation, foundations and structural, excavation and site preparation, roads and railroads, electrical equipment, instrumentation, and buildings.

Indirect capital costs consist of engineering design and supervision, architect and engineering contractor expenses, construction expenses, contractor fees, contingency, allowance for startup and modifications, and interest during construction. Working capital and land costs are included separately.

Annual revenue requirements are based on a first-year operating schedule of 7,000 hours. The costs are projected to mid-1980. In addition, lifetime revenue requirements are included for the three power plant sizes with both declining and constant operating schedules. Revenue requirements are divided into direct costs for raw materials, labor, utilities, maintenance, and analyses and indirect costs for capital charges, overheads, and byproduct marketing costs. Byproduct sales revenue is deducted from the total cost to obtain the net annual revenue requirements. Byproduct credit is given for sulfur, sulfuric acid, sodium sulfate, and spent anthracite.

RESULTS

The capital investment results are summarized in Table S-1 and the annual revenue requirements are summarized in Table S-2.

Capital Investment

The ACP has the lowest capital investment for new plants (119 $/kW for the 500-MW base case), followed in order of increasing capital investment by the Wellman-Lord/sulfuric acid (131 $/kW), Wellman-Lord/Resox (138 $/kW), and Wellman-Lord/Allied (141 $/kW) processes. For existing plants, the Wellman-Lord/sulfuric acid process has the lowest capital investment (132 $/kW for the 500-MW case), followed by the ACP (136 $/kW), Wellman-Lord/Resox process (139 $/kW), and the Wellman-Lord/Allied process (142 $/kW). The range is not large, however. For the base case the maximum difference is 18% and for all existing plants the maximum difference is 11%.

The major cost differences between the ACP and the Wellman-Lord processes lie in the ESP credit given to the ACP for new plant installations and the chloride removal equipment of the Wellman-Lord processes. For the base cases, the direct cost ESP credit is 9.4 $/kW and the chloride removal direct cost is 9.8 $/kW. For existing plants, in which

TABLE S-1. CAPITAL INVESTMENT

Case	Years remaining life[a]	ACP		Wellman-Lord/ sulfuric acid		Wellman-Lord/ Resox		Wellman-Lord/ Allied	
		k$	$/kW	k$	$/kW	k$	$/kW	k$	$/kW
Coal-Fired Power Unit									
1.2 lb SO_2/MBtu-heat-input allowable emission									
200 MW, 3.5% sulfur	20	34,841	174	34,207	171	36,119	181	37,994	190
200 MW, 3.5% sulfur	30	30,670	153	33,578	168	35,447	177	37,428	187
500 MW, 3.5% sulfur	25	68,249	136	66,227	132	69,690	139	71,167	142
500 MW, 2.0% sulfur	30	43,583	87	51,633	103	53,627	107	55,578	111
• 500 MW, 3.5% sulfur	30	59,702	119	65,360	131	68,771	138	70,338	141
500 MW, 5.0% sulfur	30	71,410	143	76,779	154	81,371	163	82,323	165
1,000 MW, 3.5% sulfur	25	109,563	110	103,691	104	109,166	109	109,247	109
1,000 MW, 3.5% sulfur	30	93,161	93	101,411	101	106,776	107	107,148	107
90% SO_2 removal									
500 MW, 3.5% sulfur	30	62,886	126	68,475	137	72,198	144	73,643	147
Lower (90% of base case) sulfur conversion factor	30	-	-	-	-	71,240	142	72,655	145
Wet-scrubbing fly ash removal	30	-	-	58,178	116	61,641	123	63,217	126
Oil-Fired Power Unit									
0.8 lb SO_2/MBtu-heat-input allowable emission									
500 MW, 2.5% sulfur	25	49,199	98	40,379	81	42,324	85	44,074	88

Basis: Midwestern power plant, mid-1979 costs.

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE S-2. ANNUAL REVENUE REQUIREMENTS

Case	Years remaining life[a]	ACP k$	ACP Mills/kWh	Wellman-Lord/sulfuric acid k$	Wellman-Lord/sulfuric acid Mills/kWh	Wellman-Lord/Resox k$	Wellman-Lord/Resox Mills/kWh	Wellman-Lord/Allied k$	Wellman-Lord/Allied Mills/kWh
Coal-Fired Power Unit									
1.2 lb SO_2/MBtu-heat-input allowable emission									
200 MW, 3.5% sulfur	20	10,010	7.15	9,659	6.90	11,141	7.96	11,277	8.05
200 MW, 3.5% sulfur	30	8,724	6.23	9,140	6.53	10,558	7.54	10,702	7.64
500 MW, 3.5% sulfur	25	18,957	5.42	18,415	5.26	21,709	6.20	21,366	6.10
500 MW, 2.0% sulfur	30	12,026	3.44	14,071	4.02	15,629	4.47	15,720	4.49
• 500 MW, 3.5% sulfur	30	16,820	4.81	17,892	5.11	21,107	6.03	20,788	5.94
500 MW, 5.0% sulfur	30	20,708	5.92	21,220	6.06	26,044	7.44	25,267	7.22
1,000 MW, 3.5% sulfur	25	30,427	4.35	29,464	4.21	35,615	5.09	34,386	4.91
1,000 MW, 3.5% sulfur	30	26,517	3.79	28,363	4.05	34,303	4.90	33,167	4.74
90% SO_2 removal									
500 MW, 3.5% sulfur	30	17,851	5.10	18,764	5.36	22,393	6.40	21,965	6.28
Lower (90% of base case) sulfur conversion factor	30	-	-	-	-	22,140	6.33	21,709	6.20
Wet-scrubbing fly ash removal	30	-	-	17,310	4.95	20,530	5.87	20,212	5.77
Oil-Fired Power Unit									
0.8 lb SO_2/MBtu-heat-input allowable emission									
500 MW, 2.5% sulfur	25	13,254	3.79	11,993	3.43	13,501	3.86	13,571	3.88

Basis: Midwestern power plant, mid-1980 costs.

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

the ESP credit is not given, there is little difference in capital investment between the ACP and the Wellman-Lord processes. For the oil-fired case, an existing plant that does not require chloride removal, the ACP has the highest capital investment.

In comparison of direct costs by processing area, the three Wellman-Lord processes are equivalent in all areas except byproduct manufacturing. The different off-gas and tail-gas compositions for the three end plants have little effect on the Wellman-Lord process costs. The ACP has slightly higher gas handling costs because of the additional ESP ductwork. The ACP absorption-collection area costs are about twice those of the Wellman-Lord processes because of the ESP's included. With the ESP credit for new plants applied to this area, the costs are equivalent to the Wellman-Lord absorption-collection area. Chloride removal is an important Wellman-Lord processing area cost, similar in costs to the SO_2 absorption-collection area. Regeneration area costs are about one-third higher for the ACP but the ACP costs include chloride removal. Conversely, the ACP byproduct manufacturing area costs are much lower than the Wellman-Lord byproduct manufacturing area costs. The combined regeneration and byproduct manufacturing area costs are similar for the ACP and Wellman-Lord processes.

In comparison of the byproduct manufacturing area costs of the three Wellman-Lord processes, the sulfuric acid version is lowest and the Resox and Allied versions 22% and 35% higher. The Resox unit has higher reactor costs because of complex piping and support structure. The Allied unit, however, has higher coal grinding and sulfur collection costs.

In case variations, increasing power unit size results in economies of scale, in terms of FGD cost per unit of power capacity, for all processes. Increasing coal sulfur content from 2% to 5% increases ACP capital investment about two-thirds and the Wellman-Lord processes capital investment about 50%. The larger ACP increase occurs because a larger percentage of its costs is directly related to sulfur rates. SO_x removal efficiencies and SO_2 conversion efficiencies have little effect on capital investment. Combined wet-scrubbing fly ash and chloride removal increase the prescrubber costs only 8%, by 0.8 $/kW. Applying an ESP credit of 9.4 $/kW results in a substantial reduction in overall fly ash and SO_x emission control costs for the Wellman-Lord processes.

Capital investment for all processes is lower for the oil-fired case than for the base case because of lower flue gas and sulfur rates. The Wellman-Lord processes capital investments are further reduced because chloride removal is not required.

Annual Revenue Requirements

The annual revenue requirements for the ACP and Wellman-Lord processes follow the same general pattern as capital investments for new and existing plants because of the indirect costs based on capital investment. For the 500-MW base cases, the annual revenue requirements

for the ACP are 4.81 mills/kWh, followed by the Wellman-Lord/sulfuric acid process at 5.11 mills/kWh, the Wellman-Lord/Allied process at 5.94 mills/kWh, and the Wellman-Lord/Resox process at 6.03 mills/kWh. Direct costs, consisting of raw material and conversion costs, for the ACP are one-fifth to two-fifths lower in all cases. Reducing coal costs are the largest raw material cost for all three sulfur-producing processes. The ACP utility costs are one-half those of the Wellman-Lord processes, primarily because it requires no process and reheat steam. About one-third of its utility requirements are for fuel oil, however. Fuel oil price increases could increase ACP utility costs disproportionally, compared with the Wellman-Lord processes.

Among the Wellman-Lord processes, the sulfuric acid version has the lowest annual revenue requirements because of lower raw material costs, lower byproduct manufacturing costs, and a higher byproduct credit. The Allied version has slightly lower annual revenue requirements than the Resox version. This is largely because of lower raw material costs for reducing coal for the Allied version, and in spite of the additional byproduct credit to the Resox version for spent anthracite.

The annual revenue requirements for the FGD processes are sensitive to unit size and coal sulfur level and are relatively insensitive to increased SO_x removal efficiency, reduced SO_2 conversion, and combined wet-scrubbing fly ash removal. The annual revenue requirements for each of the FGD processes approximately triple as the power unit size increases from 200 to 1000 MW. The economy of scale for the larger units results from more efficient use of labor, supervision, and maintenance and lower indirect costs. Annual revenue requirements increase 70% for the ACP and 50% to 60% for the Wellman-Lord processes as coal sulfur content increases from 2% to 5%. Raw material costs more than triple; utility, labor, supervision, and maintenance costs double; indirect costs increase one-half; and byproduct credits more than triple. For the oil-fired case the three sulfur-producing processes are essentially equivalent in annual revenue requirements, primarily because of reduced indirect costs for the Wellman-Lord versions.

Energy requirements for the ACP are about one-third those of the Wellman-Lord processes, primarily because it does not require steam. About one-third of its energy requirements are in the form of fuel oil, however. The gross energy requirements, primarily steam and electricity, are similar for the three Wellman-Lord processes. An energy credit for spent anthracite reduces the Resox version energy requirements about one-fifth, however.

Lifetime Revenue Requirements

The lifetime revenue requirements are shown in Table S-3. The cost relationships are similar to those of the annual revenue requirements but higher because of the declining operating schedule with increasing age.

TABLE S-3. LIFETIME REVENUE REQUIREMENTS

Case	Years remaining life[a]	Mills/kWh							
		ACP		Wellman-Lord/sulfuric acid		Wellman-Lord/Resox		Wellman-Lord/Allied	
		Actual	Levelized[b]	Actual	Levelized[b]	Actual	Levelized[b]	Actual	Levelized[b]
Coal-Fired Power Unit									
1.2 lb SO_2/MBtu-heat-input allowable emission									
200 MW, 3.5% sulfur	20	14.88	13.52	14.36	13.07	15.82	14.47	16.32	14.90
200 MW, 3.5% sulfur	30	8.81	8.80	9.28	8.45	10.45	9.57	10.71	9.78
500 MW, 3.5% sulfur	25	8.79	8.78	8.49	7.54	9.61	8.60	9.58	8.56
500 MW, 2.0% sulfur	30	4.88	4.43	5.69	5.19	6.20	5.68	6.29	5.75
• 500 MW, 3.5% sulfur	30	6.77	6.17	7.22	6.60	8.26	7.59	8.22	7.54
500 MW, 5.0% sulfur	30	8.26	7.55	8.54	7.81	10.08	9.29	9.89	9.10
1,000 MW, 3.5% sulfur	25	7.01	6.23	6.71	5.98	7.73	6.96	7.56	6.79
1,000 MW, 3.5% sulfur	30	5.30	4.85	5.67	5.20	6.61	6.11	6.46	5.96
90% SO_2 removal									
500 MW, 3.5% sulfur	30	7.17	6.54	7.57	6.92	8.74	8.04	8.66	7.95
Lower (90% of base case) sulfur conversion factor	30	-	-	-	-	6.43	7.23	8.55	7.86
Wet-scrubbing fly ash removal	30	-	-	6.84	6.27	7.87	7.27	7.83	7.21
Oil-Fired Power Unit									
0.8 lb SO_2/MBtu-heat-input allowable emission									
500 MW, 2.5% sulfur	25	6.23	5.50	5.42	4.82	5.95	5.33	6.05	5.41

a. Plants with 30 years of remaining life are new, with 127,500 hours of operating life. Plants with 25 years of remaining life have 92,500 hours of operating life. Plants with 20 years of remaining life have 57,500 hours of operating life.
b. Discounted at 11.6%.

CONCLUSIONS

Integration of fly ash and chloride removal functions with the FGD process is a major factor in the capital investment relationships of the ACP and the Wellman-Lord processes. Actual capital investments, exclusive of ESP credits, are similar for both processes. Under various circumstances in which fly ash removal credits and chloride removal requirements differ either the ACP or the Wellman-Lord process could have the lower capital investment.

The annual revenue requirements follow the same general relationships among the processes as the capital investments as a result of indirect costs related to capital investment. The ACP is substantially lower in direct costs than the three Wellman-Lord processes, primarily because it does not require process or reheat steam. Among the larger direct cost elements of annual revenue requirements of all four processes are maintenance, operating labor and supervision, electricity, steam, raw materials, and byproduct credit.

Energy requirements for the ACP are much lower than those of the Wellman-Lord processes because it does not require process and reheat steam. The gross energy requirements (without byproduct energy credits) of the three Wellman-Lord processes are similar.

Insofar as stage of development may be likely to affect cost relationships, the ACP can be considered most susceptible to cost changes because the regeneration system has not been demonstrated in a utility FGD installation. The Resox and Allied units are in a similar stage of development but represent a smaller portion of the overall FGD costs.

COMPARISON WITH PREVIOUS STUDIES

In the previous studies of this series five other processes were evaluated using the same premises. Three, the limestone, lime, and double alkali processes, produce a waste slurry that is disposed of in a pond. A slurry of magnesium oxide is used as the scrubbing medium in the magnesia process. The spent slurry is dewatered, dried, and thermally decomposed to regenerate the magnesium oxide and produce SO_2 which is converted to sulfuric acid in a conventional acid plant. The citrate process is a wet scrubbing process using a sodium citrate solution as the absorbent. The absorbent is regenerated and the SO_x compounds reduced to elemental sulfur by liquid-phase reduction using H_2S. The H_2S is produced by reducing some of the product sulfur using natural gas.

The base-case costs for each of the nine processes are shown below. Except for the ACP the costs fall into separate groupings of waste-, acid-, and sulfur-producing processes in both capital investment and annual revenue requirements. The difference in cost between the waste-producing and acid-producing processes is essentially for absorbent regeneration; ponding costs and acid plant costs do not differ greatly

and raw material costs do not differ sufficiently to produce large cost differences. The higher costs for sulfur-producing processes are the result of the added costs for reduction of sulfur oxides. Here coal reduction holds a strong advantage over other fossil reducing agents. In the citrate process, 16% of the annual revenue requirements are for natural gas to produce H_2S.

	FGD process economics[a]	
	Capital investment, $/kW	Annual revenue requirement, mills/kWh
Waste Processes		
Limestone	98	4.02
Lime	90	4.25
Double alkali	101	4.19
Sulfuric Acid Processes		
Magnesia	132	5.08
Wellman-Lord/sulfuric acid	131	5.11
Sulfur Processes		
ACP	119	4.81
Wellman-Lord/Resox	138	6.03
Wellman-Lord/Allied	141	5.94
Citrate	143	6.44

a. Although the accuracy limits associated with cost estimates of this type are normally -20, +40%, when comparing FGD process cost estimates of similar type, the accuracy limits are on the order of ±10%.

The lower costs for the ACP compared with the other sulfur-producing processes are largely the result of the combination of fly ash and SO_x particulate matter removal. For the existing plant case variation, which mainly differs from the base case in having no ESP credit, the ACP capital investment is 136 $/kW and the annual revenue requirements are 5.42 mills/kWh.

RECOMMENDATIONS

The nine processes in this series of evaluations are in diverse stages of continuing development. Future design and operating information will probably have important economic effects, as will economic and environmental regulation changes. The processes evaluated in this series should be monitored and reassessed as further information becomes available. The cost relationships of well-developed, waste-producing processes should be reassessed in respect to changing waste-disposal practices. The economic effects of the quantities and types of energy requirements should also continue to be emphasized.

DEFINITIVE SO_x CONTROL PROCESS EVALUATIONS:

AQUEOUS CARBONATE AND WELLMAN-LORD

(ACID, ALLIED CHEMICAL, AND RESOX®)

FGD TECHNOLOGIES

INTRODUCTION

For more than a decade, the Tennessee Valley Authority (TVA) has conducted a program of systematic analysis of the economics of flue gas desulfurization (FGD) processes and related technology for electric utility power plants. During this period both the comprehensive environmental legislation now regulating sulfur oxides (SO_x) emissions and much of the FGD technology to conform to the regulations have evolved. TVA's economic evaluation procedures have similarly evolved and expanded to meet the demands of legislative, technical, and economic changes. Many of these studies have been sponsored by the U.S. Environmental Protection Agency (EPA) as part of its FGD research and development program. The basic objective is, first, to present economic analyses based as closely as possible on current U.S. utility power plant conditions in which FGD is likely to find the widest and most useful application and, second, to conform to a consistent basis of analysis so that comparisons among processes will be both equitable and generally applicable.

The basis of the analyses is a conceptual design of a process for a 500-MW power unit at a midwestern coal-fired power plant. From this base-case condition, case variations are developed to assess the effects of power unit size and fuel conditions, FGD requirements, and other conditions likely to affect FGD costs. The FGD economics are based on regulated utility economics. They are developed for both capital investment to construct the FGD system and revenue requirements for its operation. For most of these studies the FGD design is based on control of SO_x and particulate matter emission to meet the 1.2 lb of SO_2 and 0.1 lb of particulate matter per MBtu of heat input promulgated by the 1971 new-source performance standards (Federal Register, 1971). The more stringent revised new-source performance standards (NSPS) promulgated in 1979 (Federal Register, 1979) will apply to new power plants coming on line by the mid-1980's, beyond the period upon which this study is based.

For many of these studies the limestone wet scrubbing process has served as a standard against which other FGD processes could be compared. Although this widely used and relatively economical process still serves as a useful standard, the increasing comprehensiveness of environmental

regulations and the growth of FGD technology now often demand more complex comparisons. The growing recognition of the economic and legislative restrictions on waste disposal may, for example, require a careful economic assessment of numerous process variations. The emerging spray dryer FGD technology has the promise of reducing many characteristic disadvantages of wet scrubbing processes. The continuing development of regeneration processes offers an increasingly diverse selection of alternates to waste-producing processes. Not only the quantity but the type of raw materials and utilities required have also become increasingly important as energy costs have risen.

This study is the third of a series begun in 1977 to evaluate recent trends in FGD technology and energy use. The first two studies (Tomlinson et al., 1979; Anderson et al., 1980) dealt with both new and updated FGD processes and also addressed the question of overall energy consumption of FGD processes. This study deals with two emerging technologies, the so-called dry FGD processes using spray dryers and processes that produce sulfur from concentrated SO_2 using coal as the reducing agent. Spray dryer FGD has developed rapidly in the past few years. It holds promise of avoiding the large volumes of liquid and related corrosion, scaling, and flue gas reheating that are associated with wet scrubbing FGD. Its removal efficiency with high-sulfur coals remains to be demonstrated, however. The use of coal as a reducing agent similarly holds promise as a method of avoiding the use of scarce and cost-sensitive reducing agents such as natural gas. Although such use of coal is not a new technology it has only recently been applied to FGD processes in a systematic manner.

The Rockwell International aqueous carbonate process (ACP) combines both spray dryer FGD and coal reduction. It is presently the most advanced of spray dryer regeneration processes and the only one to have advanced to the construction of a demonstration unit. Both the Resox® process, under developmemt by the Foster Wheeler Energy Corporation, and the Allied Chemical coal/SO_2 reduction process, being developed by the Allied Chemical Corporation, are in an intermediate stage of development. Both are end plants, in the manner of a sulfuric acid plant or a Claus plant, that process the off-gas of an FGD system. The Wellman-Lord process is used in this study for the FGD system. It is one of the most advanced of regeneration FGD processes and has been evaluated in earlier TVA economic studies (McGlamery et al., 1975) and by others (Beychok, 1980). It is included in this study because of the numerous technical changes made in the process since the earlier studies.

PROCESS BACKGROUND AND DESCRIPTION

SODIUM-BASED FGD PROCESSES

Sodium-based FGD processes have not been widely used in electric utility applications in spite of the favorable solubility and reactivity characteristics of sodium-based absorbents. The high cost of sodium absorbents, compared with limestone, or even lime, has been a deterent to processes in which a sodium-salt waste is produced. Environmental problems with the highly soluble sodium-salt waste could also be an obstacle in some climates. Most sodium-based FGD processes are either double-alkali or recovery processes. In the double-alkali processes, the sodium-based scrubbing solution is treated with a precipitant such as limestone or lime to form a calcium-sulfur salt waste and regenerate the sodium solution for reuse. Variations of this process are offered by several vendors (Kaplan, 1979). A generic double-alkali process was evaluated in a previous study in this series of economic evaluations (Tomlinson et al., 1979). In recovery processes the absorbent is also recovered, but instead of a calcium-sulfur salt waste, sulfur or a sulfur compound is produced.

Under some site-specific circumstances processes producing a sodium-based waste have proved desirable. FGD systems using Na_2CO_3 are in operation at the Reid Gardner Station of Nevada Power where the waste is disposed of in an evaporation pond. In addition, the dry absorbent waste-producing processes based on sodium, which are discussed below, have created considerable interest, particularly in the West. Waste-producing sodium processes are thus far regional, however, confined to locations where lower-cost natural sodium salts are available or where low-sulfur coal reduces absorbent requirements, and where the climate allays concerns about the soluble waste.

Among these sodium-based recovery processes producing a salable byproduct, the Wellman-Lord process is the most widely used (Laseke and Devitt, 1979). The Wellman-Lord process evaluated in this study is an updated version of the one previously evaluated, using slightly different design and economic premises, in an earlier TVA study (McGlamery et al., 1975). The Rockwell International ACP, which is also evaluated in this study, is the first sodium-based recovery process to use a spray dryer for SO_2 removal. Another sodium-based, sulfur-producing process, the citrate process, was evaluated in an earlier phase of these studies (Tomlinson et al., 1979).

Some sodium-based recovery processes are more adaptable to sulfur production than to sulfuric acid production. The Wellman-Lord process, which produces a concentrated SO_2 off-gas, can be adapted to either, although the off-gas must be diluted for processing in a standard contact acid plant. The ACP produces H_2S, which can be converted to sulfur using established technology. The citrate process is designed to produce sulfur directly by reactions in solution. In contrast, processes producing a dilute, O_2-rich SO_2 off-gas such as the magnesia process (Anderson et al., 1980) require further off-gas processing before the SO_2 can be economically reduced to sulfur.

The reduction of sulfur from oxidized states to elemental sulfur, either directly or through intermediates, is widely practiced in the chemical industry. Several processes are used in the paper industry for recovery of sulfur during regeneration of pulp digestion liquor (Tomlinson, 1968). The relatively straightforward reduction chemistry is complicated, however, by the thermodynamic tendency for the sulfur to go to the sulfide under many practical operating conditions. The proper feedstock and careful control of conditions are necessary for the direct reduction of sulfur oxides to elemental sulfur. However, if the sulfide species is H_2S, it can be readily oxidized to elemental sulfur by a number of routes, including the familiar Claus converter (Maddox and Burns, 1968) widely used in industry.

The reduction of sulfur in the form of Na_2SO_3 and Na_2SO_4 presents additional processing problems (Lowell, 1978). Unlike the sulfites and sulfates of some cations, such as magnesium, which can be thermally decomposed to the oxide and SO_2, the corresponding sodium salts melt and disproportionate to Na_2S and Na_2SO_4. Therefore the reduction must be performed in a molten salt bath reactor at a high temperature. Since much of the sulfur is reduced to the sulfide form, it must be oxidized to elemental sulfur.

A number of processes exist for carbonation of Na_2S solutions to produce Na_2CO_3 and elemental sulfur. Many of these are associated with pulp liquor processing in the paper industry (Tomlinson, 1968). The carbonation process used in the ACP is a variation of these processes, developed specifically for the ACP.

DRY ABSORPTION

Dry absorption, or "dry sorption," has been described as "any process that directly produces a dry product . . ." (Lutz and Chatlynne, 1979). Included in this definition are processes using direct injection of dry absorbents into the boiler or flue gas as well as processes which use a spray dryer. Dry absorption processes have several potential economic and technical advantages over wet FGD processes that have been long recognized by those concerned with SO_2 emission control (Tennessee Valley Authority, 1968). These advantages have been widely discussed (Bechtel, 1976; Lutz and Chatlynne, 1979; Davis et al., 1979). Paramount are the simplicity and operational flexibility of the process, reduced

energy requirements, production of a dry product, and the opportunity for simultaneous collection of fly ash and sulfur-salt waste.

Direct injection of lime was investigated in the early part of this century (Air Pollution Control Association, 1977). Widespread interest, however, paralleled the development of practical particulate matter control devices for flue gas in the 1960's, particularly fabric filters. The use of fabric filters for collection has the advantage of providing additional contact of flue gas and unreacted absorbent as it passes through the built-up solids on the filters. Bechtel (1976) has summarized early electric utility investigations of direct injection of dry adsorbents and the development of particulate matter control technology in utility applications.

A number of absorbents were evaluated during these studies, including dolomite, limestone, quicklime, hydrated lime, sodium bicarbonate, soda ash, and nahcolite. Bechtel (1976) in summarizing these studies concluded that only sodium-based absorbents were sufficiently reactive to warrant further investigation in dry-injection FGD processes. Of the absorbents tested, nahcolite (a naturally occurring sodium bicarbonate) proved most effective, exceeding both soda ash and manufactured sodium bicarbonate in removal efficiency. Nahcolite has, therefore, attracted much attention for use in dry absorption FGD processes (Lutz et al., 1979; Rajaram et al., 1979). Large reserves exist in Colorado but are not presently mined because of economic and environmental uncertainties. Commercial sodium bicarbonate is prohibitively expensive for use as a nonregenerated absorbent and soda ash, although less expensive, is considerably less efficient than sodium bicarbonate.

Notwithstanding the poor utilization rates and removal efficiencies of most absorbents, the high cost of the most effective absorbents, and the present unavailability of the most promising absorbent, development work has continued (Lutz and Chatlynne, 1979). By the early 1970's, however, the potential of dry-collection FGD processes demonstrated in the early dry-injection studies had led to further refinements. One of these was to increase the reactivity of the injected absorbent by introducing it into the flue gas as a solution or slurry, with the concentration adjusted for complete evaporation of the water before collection of the resulting particles. The increase in efficiency permits higher removal efficiencies and greater absorbent utilization, thus expanding the scope of potential application to higher sulfur coals as well as increasing the number of potential absorbents. Commercial spray dryer technology was available for adaptation to this purpose. In fact, spray dryers of sizes and types directly adaptable to FGD had been in commercial use for decades before their use in FGD technology.

The union of spray drying and particulate matter collection, both well-developed technologies, in an FGD process has proved fruitful. Atomics International (then a separate division of Rockwell International) began pilot-scale tests at Mohave Station in 1972 and at Bowen Engineering, Inc., (now Stork-Bowen Engineering, Inc.) in 1973. By 1977, in a joint venture with Wheelabrator-Frye, Rockwell International began

operating a 3000-aft^3/min pilot plant at the Leland Olds Station of the Basin Electric Power Cooperative (Janssen and Eriksen, 1979). This was a study for a nonregenerable FGD system to be installed at the Coyote Station, a lignite-fired power plant planned by a consortium headed by the Otter Tail Power Company. Soda ash, lime, fly ash, and lime - fly ash mixtures were evaluated as absorbents, and an ESP and a baghouse for particulate collection. As a result of this program, Rockwell International and Wheelabrator-Frye received the contract for the FGD system on the 410-MW Coyote Unit 1. The FGD system, scheduled for operation in 1981, will use soda ash as the absorbent and a fabric filter baghouse for particulate collection.

Three other companies constructed pilot plants for the Coyote project. Niro Atomizer, Inc., a spray dryer manufacturer, began research on FGD in 1975. In 1977 they formed a joint venture with the Western Precipitation Division of Joy Manufacturing Company to build a 20,000-aft^3/min pilot plant at the Hoot Lake Station of the Otter Tail Power Company. Babcock and Wilcox operated an 8,000-acfm unit of the William J Neal No. 2 unit using an ESP for collection. The Carborundum Company built a 10,000-acfm pilot plant at Leland Olds No. 1 using a De Laval spray dryer and a baghouse for collection.

All of these pilot plants were installed on lignite-fired boilers and the contracted commercial units will be on lignite-fired units. The lignite sulfur contents will range from 0.88% to 0.54% and the removal efficiencies from 62% to 85% (Smith et al., 1979). The spray-dryer process has yet to be demonstrated on high-sulfur coals at removal efficiencies sufficient to meet the revised NSPS (Federal Register, 1979) with economically acceptable absorbent utilization. Several other companies are now investigating spray-dryer FGD technology. Most, but not all, of these are involved with investigations using low-sulfur western coals.

Spray-dryer FGD thus appears an attractive technology. However, there are two problems associated with sodium-based spray dryer FGD that seem unlikely to be alleviated by technical advances. These are the high cost of the sodium-based absorbents and the solubility of the resulting sodium-salt wastes. As in the case of high-cost absorbents in wet scrubbing processes there is the possibility of regenerating the absorbent and producing a marketable sulfur compound. Thus far, the most advanced of such processes is the ACP included in this study.

THE ROCKWELL INTERNATIONAL ACP

The ACP (see flow diagram, Figure 1) uses a spray-dryer system similar to the one used in the Rockwell International/Wheelabrator Frye two-stage open-loop process. In the ACP, however, some fly ash is removed from the flue gas before it enters the spray dryer to facilitate processing of the sodium-sulfur salts. Flue gas entering the spray dryer contacts an atomized solution of soda ash. The process, contrary to normal spray-drying technology, uses three rotary atomizers per dryer

for redundancy and turndown capacity. Moore et al. (1979) have discussed the rationale for the use of multiple atomizers. The SO_2 in the flue gas reacts with the Na_2CO_3 to form Na_2SO_3 (and some Na_2SO_4). The sulfur salts and unreacted absorbent are converted to particulate matter as the liquid evaporates and are collected, along with residual fly ash, in conventional particulate matter removal equipment.

The collected particulate matter is combined with a carbon source such as petroleum coke or coal and passed through a molten-salt reactor. Sufficient excess carbon is added to maintain the reaction temperature of 1700°F to 1900°F (927°C to 1038°C). Air is blown through the melt to maintain the reaction temperature. The reactions, in simplified form, are:

$$Na_2SO_3(lq) + 3/2C(s) \rightarrow Na_2S(lq) + 3/2CO_2(g)$$

$$Na_2SO_4(lq) + 2C(s) \rightarrow Na_2S(lq) + 2CO_2(g)$$

$$C(s) + O_2(g) \rightarrow CO_2(g) + \text{heat}$$

According to Gehri and Oldenkamp (1976), the Na_2SO_3 probably does not react directly but disproportionates to Na_2SO_4. Also, the oxidation of carbon probably proceeds along the pathway:

$$Na_2S + 2O_2 \rightarrow Na_2SO_4 + \text{heat}$$

$$Na_2SO_4 + 2C \rightarrow Na_2S + 2CO_2$$

The overflow from the reducer--consisting of Na_2S, fly ash, and other impurities--is quenched, shattered with steam, and dissolved to form a "green liquor." The green liquor is a highly alkaline solution of sodium sulfide, and sodium hydrosulfide and sodium hydroxide formed by hydrolysis of the sulfide. The green liquor (the name comes from wood pulping technology in which the liquid is colored by iron compounds) is treated in a precarbonator with a portion of the hydrogen sulfide generated in later stages of the process to form NaHS:

$$Na_2S(aq) + H_2S(g) \rightarrow 2NaHS(aq)$$

$$NaOH(aq) + H_2S(g) \rightarrow NaHS(aq) + H_2O(aq)$$

The solution in the precarbonator is also circulated through a filter loop to remove solids, mostly fly ash.

The NaHS is converted to $NaHCO_3$ and then to Na_2CO_3 in a two-stage process using CO_2 obtained from the reducer and decomposer off-gas. The overall reactions are:

$$NaHS(aq) + CO_2(g) + H_2O \rightarrow NaHCO_3(aq) + H_2S(g)$$

$$2NaHS(aq) + CO_2(g) + H_2O \rightarrow Na_2CO_3(aq) + 2H_2S(g)$$

The H_2S stream is divided, part returning to the precarbonator and the remainder to a Claus plant. The $NaHCO_3$ is then thermally decomposed in a decomposer.

$$2NaHCO_3(aq) \rightarrow Na_2CO_3(aq) + H_2O + CO_2(g)$$

The Na_2CO_3 solution, with makeup soda ash added, is reused in the process.

The reducer off-gas is used to heat the reducer air and produce process steam before being scrubbed to remove particulate matter. The cleaned gas, rich in CO_2, but also containing CO and H_2S, is used in the carbonation process. Because of the high temperature of the reduction reaction, the off-gas is enriched in chlorides removed from the flue gas. A stream withdrawn from the off-gas cooling tower thus serves as a chloride purge. The process also includes a waste gas incinerator for the Claus plant tail gas, the precarbonator off-gas, and tail gas from the reducer off-gas treatment system.

Rockwell International began development of the ACP regeneration system in the early 1970's at their molten salt test facility. Pilot-scale evaluations were made of molten-bath reduction of sodium-sulfur salts using petroleum coke as the reducing agent. Separate tests were made of the filtration characteristics of solutions of the reduced salt. Although commercial processes exist for the processing of the reduced salt, Rockwell developed their own proprietary process.

The ACP has not been demonstrated in its entirety in a power plant installation. A 100-MW scrubbing, 60-MW regeneration unit is, however, being installed at Niagara Mohawk Power Corporation's Huntley Steam Station (Binns and Aldrich, 1978). Construction on the unit began in 1979.

WELLMAN-LORD PROCESS

The Wellman-Lord process (see flow diagram, Figure 5) was developed by Davy Powergas in the mid-1960's as a potassium-based process (Sulfur, 1967). This version was tested on a pilot-plant scale at the Tampa Electric Company and later at the Baltimore Gas and Electric Company. The first sodium-based process was installed at an Olin Corporation sulfuric acid plant at Paulsboro, New Jersey, in 1970. In the 1970's the process was installed on a number of oil-fired boilers, sulfuric acid plants, and Claus plants in the United States and Japan. By 1978 twenty-four commercial installations were in operation, scrubbing 4.3 million sft^3/min of gas (Davy Powergas, 1979). According to Davy Powergas (Gaur, 1978) all of these units achieved greater than 90% SO_2

removal efficiency and had an absorption-area on-stream efficiency of over 97%. The largest of these applications is on a 220-MW oil-fired peaking plant in Japan, in which the system has been able to successfully follow load changes of 35% to 150% of rated capacity.

The first coal-fired boiler applications are now operating on a 115-MW unit at the Dean H. Mitchell Station of Northern Indiana Public Service Company and on two units of about 350 MW each at the San Juan Station of the Public Service Company of New Mexico. Two additional units of over 1000 MW total capacity are under construction at the San Juan plant (Smith et al., 1979).

The NIPSCO plant, amply described in the literature (Mann and Christman, 1976; Ross et al., 1979; Link and Ponder, 1978), is a demonstration project partially funded by EPA to demonstrate an FGD process producing elemental sulfur. The installation represented the first combination of the Wellman-Lord process with the Allied Chemical methane (natural-gas) reduction process. The unit was started up in 1977 and has completed performance testing.

The Wellman-Lord process is a sodium-based process which utilizes the inherent solubilities of sodium compounds as well as the relative solubilities of the different species. The scrubbing medium is a solution of Na_2SO_3 that reacts with SO_2 absorbed from the flue gas to form $NaHSO_3$,

$$Na_2SO_3(aq) + SO_2(aq) + H_2O \rightarrow 2NaHSO_3(aq)$$

Because the bisulfite is about twice as soluble as the sulfite at the absorber conditions used, a saturated scrubbing solution can be used without formation of solids or potential scale formation in the absorber. The use of a highly concentrated scrubbing solution, in addition to reducing the quantity of liquor handled, reduces oxygen absorption, thus reducing oxidation of the sulfite. Oxidation to sulfate occurs along two pathways in the absorption section, reaction of the sulfite with dissolved oxygen and with dissolved SO_3.

$$Na_2SO_3(aq) + 1/2O_2(aq) \rightarrow Na_2SO_4(aq)$$

$$2Na_2SO_3(aq) + SO_3(aq) + H_2O \rightarrow Na_2SO_4(aq) + 2NaHSO_3(aq)$$

An antioxidant that was formerly added to the scrubber liquor (but has not proven economically feasible) is no longer used. Instead Davy Powergas has redesigned the absorption system such that at the design conditions used in this study only about 3% of the SO_2 absorbed is converted to sulfate (including that formed in the recovery section, as discussed below).

The formation of sulfate in the Wellman-Lord process must be minimized because the sulfate remains in solution as an inert common-ion component and can eventually decrease the reactivity of the solution. This is

accomplished by the crystallization of Na_2SO_4 in a purge stream by taking advantage of the lower solubility of the sulfate compared with the sulfite and particularly the bisulfite. The purge stream is concentrated by evaporation and the crystalline solid formed (consisting of about two-thirds Na_2SO_4 and one-third Na_2SO_3) is removed and dried. Although the technology for reduction of Na_2SO_4 is known (Tomlinson, 1968), it has not been used in FGD applications of the Wellman-Lord process. Davy Powergas is, however, investigating processes for conversion of the Na_2SO_4 to a sodium compound reusable in the process (Radian, 1977).

The Na_2SO_4 is a potentially marketable product. About 1.3 million tons is produced annually in the United States from natural deposits and as a byproduct of chemical processes. Over half is used in kraft paper manufacture, a use anticipated to decline in the future (Pulp and Paper, 1979).

The $NaHSO_3$-rich solution from the absorber and the sulfate purge evaporator is regenerated by evaporative heating under vacuum.

$$2NaHSO_3(aq) \rightarrow Na_2SO_3(s) + SO_2(g) + H_2O(g)$$

The reaction is favored by the lower solubility of Na_2SO_3 which is removed from solution and redissolved for reuse.

In addition to the previously mentioned sulfite oxidation reaction and the SO_3 absorption reaction which take place in the absorber, other reactions which further reduce the quantity of active absorbent occur during regeneration.

$$6NaHSO_3(aq) \rightarrow 2Na_2SO_4(s) + Na_2S_2O_3(aq) + 2SO_2(g) + 3H_2O(g)$$

$$2NaHSO_3(aq) + 2Na_2SO_3(aq) \rightarrow 2Na_2SO_4(aq) + Na_2S_2O_3(aq) + H_2O$$

Most of the Na_2SO_4 returns to the absorber system and is controlled by the sulfate purge. The concentration of the relatively small quantity of highly soluble $Na_2S_2O_3$ formed is controlled by a liquid purge stream which is combined with the sulfate purge solids. These reactions are also reduced by operating the regeneration process at the lowest practical temperature.

Sodium losses are replaced by addition of soda ash to the scrubber solution.

$$Na_2CO_3(aq) + SO_2(aq) \rightarrow Na_2SO_3(aq) + CO_2(g)$$

The evaporator off-gas is dewatered, by cooling and compression to atmospheric pressure, to a concentration of about 96% SO_2. The SO_2 can be liquefied, processed to H_2SO_4, or reduced to elemental sulfur. All three routes have been used, in the United States or Japan. Conventional

technology is well known for liquefaction and H_2SO_4 production. Reduction to elemental sulfur, a more tractable, and in some aspects a more widely marketable product (O'Brien and Anders, 1979), is the method used at the three commercial Wellman-Lord utility FGD systems now in operation in the United States (Gaur, 1979). The Allied Chemical methane (natural-gas) reduction process discussed below is used at these installations.

RESOX® COAL-REDUCTION PROCESS

The Resox process (see flow diagram, Figure 10) is being developed by the Foster Wheeler Energy Corporation. It is based on the direct reduction of SO_2 to sulfur by passing it through a bed of anthracite coal at an elevated temperature. Steam and air are added to the inlet SO_2 stream as essential components of the reduction reactions. According to Foster Wheeler (Steiner et al., 1974) the water acts synergistically to permit high conversions at lower operating temperatures. The air acts as an oxidizing agent to control volatiles and maintain the reaction temperature. By careful control of conditions, particularly temperature and residence time, Foster Wheeler claims a conversion of SO_2 to sulfur of 90%. The operating temperature is 1100°F to 1500°F and the gas residence time is 3 to 8 seconds, depending on the coal used and the SO_2 feed stream characteristics. Neither SO_2 nor steam reacts readily with carbon at the temperatures used in the Resox process. Since the quantity of steam entering the reactor is about the same as the quantity leaving, it has been postulated that carbon is the primary reducing agent, with carbon-water reaction products serving as intermediaries (Radian, 1976).

$$C + H_2O \rightarrow H_2 + CO$$

$$SO_2 + 2H_2 \rightarrow S + 2H_2O$$

Catalytic effects of the anthracite coal, perhaps specific to this or similar coals, have also been suggested (Radian, 1977).

Stoichiometry is not considered a critical factor if excess carbon is available. A stoichiometric molar ratio of about 2 carbon to 1 sulfur is used. The spent coal from the reactor thus contains appreciable fuel value. Its use as a boiler fuel (Radian, 1977) or as a carbon adsorbent has also been suggested. The use of anthracite instead of other coals has been dictated thus far by the need of a free-flowing, nonvolatile coal. Foster Wheeler has evaluated other coals but has found them less practical because of caking and hydrocarbon contamination of the sulfur.

The Resox system consists of a vertical reactor into which rice-size (3/16 to 5/16 inch) anthracite coal is fed from an overhead hopper. The spent coal consisting of char and ash is withdrawn at a controlled rate at the bottom of the reactor to control the anthracite residence time, which is about 12 hours. The SO_2-rich gas is mixed with air, and steam if necessary, and injected around the periphery of the reactor

near the vertical midpoint. The quantity of air added is controlled to oxidize volatiles and oxidize sufficient coal to maintain the reaction temperature. The off-gas is composed of sulfur vapor, water vapor, CO_2, and minor amounts of H_2S, SO_2, COS, and other reaction products. The off-gas is passed through a shell and tube heat exchanger where the sulfur is condensed. The remaining off-gas is either returned to the boiler or incinerated and then returned to the FGD system.

Foster Wheeler began studies of the Resox process in the late 1960's (Steiner et al., 1974). Following studies to establish operating conditions, a demonstration unit was constructed at the Scholz Steam Plant of Gulf Power Company as part of a demonstration unit of the Bergbau-Forschung FGD process (Strum et al., 1976). The Bergbau-Forschung process, for which Foster Wheeler is the U.S. licensee, is a carbon adsorption, regeneration process that produces an SO_2 gas stream suitable for processing in a Resox unit. The demonstration unit was tested in 1975 and 1976 although only limited data were obtained before expiration of the test program. Subsequently, a Resox unit was installed at the Kellerman Power Station in Lunen, Federal Republic of Germany, again in conjunction with the Bergbau-Forschung process (Knoblauch and Goldschmidt, 1976). This unit was operated from June 1978 to June 1979 (Steiner, et al., 1980). During about half of this test period, the unit was operated on a simulated feed gas of the composition produced by the Wellman-Lord process. The Resox process is also being installed on a 10-MW experimental chemically active fluidized-bed boiler at the La Palma Power Station of the Central Power and Light Company of Corpus Christi, Texas.

ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

The Allied Chemical coal/SO_2 reduction process (see flow diagram, Figure 12) is an outgrowth of their SO_2 reduction process using methane (natural gas), which has been operational since 1970. In addition to other applications, the methane reduction process is used with Wellman-Lord scrubbing systems at Mitchell Station and San Juan Station. Pilot-plant studies based on earlier research were begun on the coal reduction variation in 1973. Since then continuing development has defined process and control techniques and improved yields and efficiencies to the extent that Allied believes the process has a good potential for successful commercial application (Allied Chemical, 1978). In addition, operational conditions for a number of different types of coal have been defined.

The coal reduction process uses ground coal as the reducing agent. The coal is ground and dried in an inert atmosphere, combined with quartz sand, and injected into the bottom of a reactor vessel. The SO_2-rich off-gas from the FGD system is combined with a small amount of air and injected at the bottom of the reactor. The gases move upward, fluidizing the bed. About 75% to 80% of the SO_2 is reduced to elemental sulfur vapor during its passage through the bed and during contact with coal particles in a low-velocity settling chamber above the bed. The temperature of the reactor is controlled at 1500°F to 1800°F (816°C to 982°C), depending on optimum reaction temperature for the particular coal used, by controlling bed depth and flow rates.

Particulate matter (consisting of ash, char, and some sand) is partially removed from the reactor off-gas in a cyclone separator. The off-gas (consisting of sulfur vapor, SO_2, various gaseous reaction products, volatilized impurities, and residual particulate matter) is scrubbed with molten sulfur in a venturi ejector to condense the sulfur vapor and remove the remaining particulate matter. The molten sulfur used in the ejector is cooled by water injection in the molten sulfur circulation system. Molten sulfur is withdrawn from the system, filtered, and pumped to storage.

Cleaned gas from the ejector, containing residual sulfur as H_2S and SO_2, is passed through a two-stage Claus unit to increase the overall conversion of SO_2 to sulfur to about 96%. Claus unit tail gas is incinerated and recycled to the scrubber system. Because of sulfur losses in both the cyclone dust and the filter cake, sulfur recovery is reduced to 90 molar % of the SO_2 in the feed stream.

The process also includes an inert gas generator, various feed preheaters using process streams, and a waste heat boiler which produces process steam.

Claus Process

The Claus process has been used in numerous variations since the 19th century for the catalytic vapor-stage oxidation of H_2S to sulfur (Maddox and Burns, 1968). The reaction proceeds in two steps:

$$2H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O$$

$$2H_2S + SO_2 \rightarrow 3/8S_8 + 2H_2O$$

Both reactions are highly exothermic, particularly the first. To optimize conversion conditions, the feed stream is partially oxidized to SO_2 at about 2000°F. Under these conditions, a considerable percentage of sulfur is formed directly. The gas is cooled in a high-pressure steam boiler and further cooled to 300°F in a low-pressure steam generator to condense and remove the sulfur. The gas is reheated to 450°F to 500°F, the optimum conversion temperature, and passed through a bed of catalyst such as alumina where the second reaction shown above occurs. The off-gas is then cooled to 300°F in a low-pressure steam generator to remove the sulfur. The gas is then passed through a second catalytic converter. Two-stage conversion usually results in a total conversion of about 90%. In conventional plants additional converters are usually preferable to reduce tail-gas processing. Many design variations are used to meet specific needs. A widely used variation is the split-stream process in which the H_2S in a side stream of the feed gas is completely oxidized to SO_2 and recombined with the remaining gas. This reduces difficulties in processing impure feed gas but usually results in a lower conversion.

In FGD applications some variations from conventional Claus plant design are possible. In some processes, such as the Allied process, the

feed gas contains both SO_2 and H_2S and partial oxidation is not necessary. In addition, additional converters and tail-gas emission control are not necessary because the tail gas can be returned to the FGD system.

DESIGN AND ECONOMIC PREMISES

The premises used in this study have been developed by TVA, EPA, and others during similar economic evaluations made since 1967. They establish base-case efficiencies, process flow rates, and other operating and design conditions. Case variations are used to determine the sensitivity of costs to changes in plant size, new versus existing plants, sulfur in coal, SO_x removal efficiency, and process variations. Because of the decreased emphasis on oil as a utility fuel, only one oil-fired variation is included. The economic premises are selected to include the many factors affecting FGD costs. They establish conditions for determination of capital costs for installation of the FGD system and first-year annual revenue requirements for its operation. Lifetime revenue requirements for each year of the systems' operating life are also calculated.

Normally, the base-case FGD systems are assumed to begin downstream from the fly ash removal system and boiler ID fans and to end at the stack plenum. Fly ash removal and disposal and a stack plenum are considered necessary power plant facilities and are not included in the FGD costs.

In previous FGD economic analyses in this series of evaluations, fly ash removal and disposal were not included in the costs because they were independent functions. In the ACP, however, fly ash collection can be performed in the same equipment used to collect the sulfur-salt particulate matter. Also, in case variations involving wet scrubbing for fly ash removal, ESP's are not required. When fly ash collection is an integral part of the FGD process, appropriate credit for ESP costs is included. By applying these costs as credits, equitable economic comparisons with other FGD processes evaluated in this series are facilitated.

DESIGN PREMISES

The power plant design and operation is based on Federal Energy Regulatory Commission (FERC) historical data and TVA experience. The conditions represent a typical modern boiler for which FGD systems would most likely be considered. A midwestern location typical of Illinois, Indiana, and Kentucky is used because of the concentration of medium- to high-sulfur coal supplies and power plants in that area.

Emission Standards

NSPS promulgated by EPA in 1971 (Federal Register, 1971) are used. These NSPS specify a maximum SO_2 emission of 1.2 lb/MBtu and a maximum particulate matter emission of 0.1 lb/MBtu, based on heat input, for large coal-fired boilers. The revised NSPS promulgated by EPA in 1979 (Federal Register, 1979) are not used because boilers existing in the time period used in this study would not be affected by these regulations. The revised NSPS retain the same SO_2 maximum emission standard and, in addition, require between 70% and 90% SO_2 emission reduction for all levels of sulfur input in the raw coal. If all SO_2 emission control were performed by FGD, the 3.5% and 5.0% sulfur coals would require removal efficiencies approaching 90%, as represented by the case variations discussed below.

Fuels

The coal compositions are composites of several hundred samples representing major U S. coal production areas. To represent the range of sulfur contents in coals now being burned, sulfur contents of 2.0%, 3.5%, and 5.0%, dry basis, are used. The coals have a heating value of 10,500 Btu/lb, as fired, and an ash content of 16%, as fired. The composition and flow rates for the base-case conditions are shown in Table 1. The oil-fired variation uses a No. 6 fuel oil (Table 2) with 2.5% sulfur and 0.1% ash and with a high heating value of 144,000 Btu/gal.

TABLE 1. COAL COMPOSITIONS AND FLOW RATES AT VARYING SULFUR LEVELS

(500-MW new unit, 9,000 Btu/kWh heat rate, 10,500 Btu/lb high heating value of coal)

Coal components	Base case, 3.5% sulfur (dry basis)		2.0% sulfur (dry basis)		5.0% sulfur (dry basis)	
	Wt %, as fired	Lb/hr, as fired	Wt %, as fired	Lb/hr, as fired	Wt %, as fired	Lb/hr, as fired
Carbon	57.56	246,800	58.03	248,700	56.89	244,000
Hydrogen	4.14	17,700	4.17	17,900	4.09	17,500
Nitrogen	1.29	5,500	1.30	5,600	1.27	5,400
Oxygen	7.00	30,000	7.81	33,500	6.40	27,400
Sulfur	3.12	13,400	1.80	7,700	4.46	19,100
Chlorine	0.15	600	0.15	600	0.15	600
Ash	16.00	68,600	16.00	68,600	16.00	68,600
Water	10.47	46,000	10.74	46,000	10.74	46,000
Total	100.00	428,600	100.00	428,600	100.00	428,600

TABLE 2. OIL COMPOSITION AND RATE

(500-MW existing unit, 9,200 Btu/kWh heat rate, 2.5% sulfur)

Oil components	Wt % as fired	Lb/hr
Carbon	83.66	204,100
Hydrogen	11.46	28,000
Nitrogen	0.63	1,500
Oxygen	1.25	3,000
Sulfur	2.50	6,100
Ash	0.10	200
Sediment	0.40	1,000
Total	100.00	243,900

Power Plant Design

For new power units scheduled for startup through 1980, the sizes range from about 80 to 1300 MW (Kidder, Peabody & Co., 1978). Although much of the future power production will be from units of 500 MW or larger, many older units and some new units of 200 MW or less will continue in operation for many years. The choice of unit sizes used in this evaluation is based on this anticipated power unit size distribution.

A single, balanced-draft, horizontal, frontal-fired boiler design is used. Boiler ID fans are not included in the FGD costs. The boiler ID fans discharge into a common plenum which is included in the FGD costs. For the ACP, the particulate matter cyclone collectors (which are included in the FGD costs) are located upstream from the boiler ID fans. A boiler size of 500-MW output is used for the base case and sizes of 200- and 1000-MW output are used for the case variations. The output does not include power requirements for the FGD system.

Power Plant Operation

An operating life of 30 years is used, based on guidelines suggested by FERC (1968). The operating schedule, based on TVA experience, is shown below. New units are assumed to have a total operating time of 127,500 hours. Existing units 5 and 10 years old are assumed to have remaining operating times of 92,500 and 57,500 hours respectively.

Operating year	Capacity factor, %	Annual operating time, hr
1-10	80	7,000
11-15	57	5,000
16-20	40	3,500
21-30	17	1,500
Average for 30-yr life	48.5	4,250

Power plant efficiencies vary with size and status. FERC (1973) data list heat rates for approximate 500-MW power units up to 5 years old, ranging from 8,800 to 12,800 Btu/kWh. Representative heat rates chosen for use in this study are shown below.

Size, MW	Status	Heat rate, Btu/kWh
1,000	New	8,700
1,000	Existing	9,000
500	New	9,000
500	Existing	9,200
200	New	9,200
200	Existing	9,500

Flue Gas Composition

Flue gas compositions are based on combustion of pulverized coal using a total air rate equivalent to 133% of the stoichiometric requirement. This includes 20% excess air to the boiler and 13% air inleakage in ducts and at the air preheater. These values reflect operating experience with TVA horizontal, frontal-fired, coal-burning units. It is assumed that 80% of the ash present in coal is emitted as fly ash and 95% of the sulfur in coal is emitted as SO_x. One percent of the SO_x emitted is assumed to be SO_3 and the remainder SO_2.

The base-case flue gas composition and flow rate calculated from these conditions are shown in Table 3. The estimated flue gas compositions for power unit emissions at varying fuel-sulfur levels before fly ash removal and FGD are shown in Table 4. Calculated flue gas and equivalent SO_2 emission rates are shown in Table 5.

TABLE 3. BASE-CASE FLUE GAS

COMPOSITION AND RATE

Flue gas components	Lb/hr	Aft^3/min (300°F)
N_2	3,450,000	1,138,000
O_2	253,200	74,590
CO_2	904,200	189,900
SO_2	25,130	3,626
SO_3	317	37
NO_x (as NO)	3,009	927
HCl	661	168
H_2O	264,500	135,600
Total	4,906,000	1,543,000

Table 4. FLUE GAS COMPOSITIONS WITHOUT

EMISSION CONTROL FACILITIES

Flue gas components % by vol	Fuel and boiler type: Coal-fired boiler (horizontal frontal fired)			Oil-fired boiler (tangential fired)
	Sulfur content of fuel, % by wt (dry basis)			
	2.0	3.5	5.0	2.5
N_2	73.68	73.76	73.80	73.60
O_2	4.83	4.83	4.84	2.54
CO_2	12.44	12.31	12.20	11.96
SO_2	0.14	0.24	0.34	0.13
SO_3	0.0014	0.0024	0.0034	0.0013
NO_x (as NO)	0.06	0.06	0.06	0.02
HCl	0.01	0.01	0.01	-
H_2O	8.84	8.79	8.75	11.75
Fly Ash Loading				
Gr/sft^3 (dry)	6.67	6.65	6.66	0.036
Gr/sft^3 (wet)	6.08	6.06	6.08	0.032

TABLE 5. POWER PLANT FLUE GAS AND SO_2 RATES

Power plant size, MW	Type plant	Sulfur content of fuel, % (dry basis)	Gas flow to FGD systems, aft^3/min (300°F)	Equivalent SO_2 emission rate to FGD systems, lb SO_2/hr
Coal-fired units				
200	Existing	3.5	652,000	10,610
200	New	3.5	631,000	10,270
500	Existing	3.5	1,577,000	25,690
500	New	2.0	1,539,000	14,500
500 (base case)	New	3.5	1,543,000	25,130
500	New	5.0	1,539,000	35,920
1,000	Existing	3.5	3,085,000	50,250
1,000	New	3.5	2,982,000	48,580
Oil-fired unit				
500	Existing	2.5	1,313,000	12,060

Removal Efficiencies

Actual SO_x removal efficiencies required to meet the 1.2 lb SO_2/MBtu emission standards vary according to the sulfur content of the coal. Shown below are the efficiencies calculated for the sulfur contents and combustion conditions used in this study. In addition, a case variation is included to evaluate the effect of 90% SO_x removal efficiency on costs.

Sulfur content of fuel, %	Degree of particulate removal, wt %	Degree of SO_2 removal, %
Coal-fired units		
2.0	99.5	62.7
3.5	99.5	78.5
5.0	99.5	85.0
Oil-fired units		
2.5	-	69.8

Absorber Design

Absorber design criteria are based on vendor-supplied data, applicable TVA operating experience, and general power industry operating experience. The designs are generic to the extent that they represent most-proven technology rather than a particular existing installation. Technical design and operating data were supplied by the vendors of each process.

The 200-MW boiler size is provided with two absorber trains; the 500- and 1000-MW boiler sizes are provided with four each. All of the trains are fed from the common plenum. Booster fans, sized to compensate for the pressure drop in the FGD system, are provided in each train.

In all the processes except the ACP, chlorides are removed in a prescrubber upstream of the SO_2 absorber. This also serves to presaturate the flue gas. The assumed percentages of flue gas components removed in the chloride scrubber are: 0% SO_2, 25% SO_3, and 100% HCl. In the ACP, chlorides are removed in the regeneration process. In all processes the chloride waste is discarded in the ash disposal pond.

The Wellman-Lord absorbers are equipped with chevron-type mist eliminators which reduce the entrained moisture content of the scrubbed gas to 0.1%. This is desirable to reduce the reheating load, decrease deposition and corrosion in downstream equipment, and reduce particulate matter emission.

Operating conditions for the Wellman-Lord absorbers and the ACP spray dryers are shown in Table 6. These conditions are used for both the base case and the case variations. Scaling factors based on gas and product rates are used to adjust sizes for conditions other than the base case.

TABLE 6. ABSORBER OPERATING CONDITIONS

[500-MW units, 3.5% sulfur in coal (dry basis), 1.2 lb SO_2/MBtu heat input allowable emission]

Operating conditions	Process			
	Aqueous carbonate	Wellman-Lord/ sulfuric acid	Wellman-Lord/ Resox	Wellman-Lord/ Allied Chemical coal/SO_2 reduction
Design gas velocity, ft/sec				
SO_2 scrubber	12.5	10	10	10
L/G, gal/kft^3				
Prescrubber	-	10	10	10
SO_2 absorber, recycle liquor	-	3	3	3
Design pressure drop, inches H_2O	15	19	19	19
Oxidation of removed SO_2 to $SO_4^=$, %	20	3	3	3

The absorber design is assumed to be proven. No provisions are made for additional spares or special sizing to compensate for uncertain design and operating factors. In the integration of the absorber system with the boiler, provision for turndown and maintenance is limited to provision of the common plenum with dampers to allow individual trains to be shut down. Absorber bypass ducts are not provided.

Reheat

In the Wellman-Lord processes, reheat of the scrubbed flue gas to 175°F is provided for plume buoyancy, to reduced opacity, and to prevent fan and stack corrosion. Indirect steam heat is used for coal-fired cases. Direct-fired oil reheat is used for the oil-fired cases. The ACP does not require reheat.

Raw Materials

The major raw materials required are soda ash, anthracite, and power-plant coal. The power-plant coal is described in the power-plant fuel premises. The same light bulk soda ash is used for both the Wellman-Lord processes and the ACP. It is assumed to be in powder form (100% to pass a U.S. No. 100 screen), contain 99.5% Na_2CO_3, and have a dry bulk density of 35 lb/ft^3.

The anthracite is rice size (ASTM, 1979), a size designation in which the coal passes a 5/16-inch round-hole screen and is retained on a 3/16-inch round-hole screen. The anthracite composition used is shown below.

Ultimate analysis, %		Proximate analysis, wt %	
C	81.8	Moisture	4.1
H	3.1	Volatiles	6.0
N	0.9	Fixed carbon	80.8
O	4.4	Ash	9.1
S	0.7		
Ash	9.1		

Other raw materials required are catalysts, agricultural limestone, filter aids, and silica sand. Standard commercial grades are used, based on vendor recommendations.

Waste Disposal

The power plant ash pond is used for waste disposal. A portion of the ash pond cost is allocated to the FGD system to account for the additional waste disposal cost.

Case Variations

Case variations, consisting of a change in one design premise while holding the remaining premises at the base-case conditions, are used to determine the economic effects of ranges of conditions normally encountered in industry practice. The case variations used are shown below:

Premise condition	Base case	Case variation
Power plant size, MW	500	200, 1000
Power plant remaining life, years	30 (new)	25, 20
Coal, percent sulfur (dry weight)	3.5	2.0, 5.0
SO_x, percent removal	79 (3.5% S)	90
Oil, weight percent sulfur	-	2.5
Alternate SO_2 conversion rate	90% (Resox) 96% (Allied)	90% of base case
Wet-scrubbing fly ash removal	No	Yes (W-L systems)

The relative quantities of gas and sulfur processed compared with the base-case quantities are shown in Table 7. The relative throughput rates are used to calculate a processing area scale factor, which multiplied by the base-case processing area direct investment gives the corresponding processing area direct investment for the case variation.

ECONOMIC PREMISES

The economic premises define procedures for determining capital investment costs for installation of the FGD system and annual revenue requirements for its operation. The premises are further divided into sections to establish cost areas for comparison and analysis. Criteria are used which define cost indexes, land, raw material, utility, energy costs, capital charges, and other factors required for comparative results. The estimates are made using equipment lists; flow diagrams; material balances; various layouts for electrical equipment, piping, and instrumentation; plot plans; and other design and operating information. Cost information is obtained from engineering-contracting, processing, and equipment companies, TVA purchasing and construction data, and authoritative publications on costs and estimating, such as Guthrie (1969), Peters and Timmerhaus (1968), Popper (1970), The Richardson Rapid System (1979), and Modern Cost Engineering (1979).

TABLE 7. RELATIVE QUANTITIES OF GAS AND SULFUR

IN COMPARISON WITH THE BASE-CASE QUANTITIES

	Relative throughput rate, %	
	Gas	Sulfur removed
Coal-Fired Power Unit		
1.2 lb SO_2/MBtu heat input allowable emission		
200 MW E 3.5% sulfur	42.22	42.22
200 MW N 3.5% sulfur	40.89	40.89
500 MW E 3.5% sulfur	102.22	102.22
500 MW N 2.0% sulfur	100.00	46.01
500 MW N 3.5% sulfur	100.00	100.00
500 MW N 5.0% sulfur	100.00	153.81
1,000 MW E 3.5% sulfur	200.00	200.00
1,000 MW N 3.5% sulfur	193.33	193.33
90% SO_2 removal		
500 MW N 3.5% sulfur	100.00	113.92
Oil-Fired Power Unit		
0.8 lb SO_2/MBtu heat input allowable emission		
500 MW E 2.5% sulfur	84.70	44.08

The premises are designed to represent projects in which design begins in mid-1977 and construction is completed in mid-1980, followed by a mid-1980 startup. Capital costs are assumed 50% expended in mid-1979. Capital costs are projected to mid-1979 and revenue requirements are projected to mid-1980. Scaling to other time periods can use mid-1979 as the basis for capital costs and mid-1980 as the basis for revenue requirement.

The premises are based on regulated utility economics. The capital structure is assumed to be 60% debt and 40% equity. Interest on bonds is assumed to be 10% and the return to stockholders 14%.

Capital Investment

Capital investment costs consist of direct investment, indirect investment, contingency, other capital charges, land costs, and working capital. Total fixed investment consists of the sum of direct and indirect capital costs and a contingency based on direct and indirect investment. Total depreciable investment consists of total fixed investment plus the other capital charges. Investment costs are projected from Chemical Engineering (1975, 1976) annual cost indexes as shown in Table 8. The costs are based on construction of a proven design and an orderly construction program without delays or overruns.

TABLE 8. COST INDEXES AND PROJECTIONS

Year	1974	1975	1976[a]	1977[a]	1978[a]	1979[a]	1980[a]	1981[a]
Plant	165.4	182.4	197.9	214.7	232.9	251.5	271.6	293.3
Material[b]	171.2	194.7	210.3	227.1	245.3	264.9	286.1	309.0
Labor[c]	163.3	168.6	183.8	200.3	218.3	237.9	259.3	282.6

a. Projections. Although actual cost indexes are available for 1976-1978, projections for these years are used so that consistency with past estimates is maintained.

b. Same as index in Chemical Engineering for "equipment, machinery, supports."

c. Same as index in Chemical Engineering for "construction labor."

Direct Investment--

Direct capital costs include all costs, excluding land, for materials and labor to install the complete FGD system. Included are site preparation, excavation, buildings, storage facilities, landscaping, paving, and fencing. One mile of paved road is also included. Process equipment includes all major equipment and all equipment ancillary to the major equipment, such as piping, instrumentation, electrical equipment, concrete foundations, structure, and vehicles. Services, utilities, and miscellaneous costs involved in construction are estimated as 6% of the direct investment excluding pond construction costs.

Indirect Investment--

Indirect investment costs consist of various contractor charges and fees and construction expenses. The following cost divisions and determinations are used.

Engineering design and supervision--This cost is calculated as a function of the complexity of the system as determined by the number of major equipment items. Battery-limit package units and incremental disposal ponds are treated separately because of the different engineering design aspects involved. The formula used is:

$$\text{Engineering design and supervision} = (8900)(1.294)(\text{number of major equipment items}) + (\text{status factor})(\text{battery-limit investment}) + (0.076)(\text{direct pond investment, in M\$})^{0.07}$$

A status factor of 0.07 is used for all battery-limits units in this study.

Architect and engineering contractor expense--This expense is calculated as 25% of the engineering design and supervision costs for major equipment items and battery-limits units plus 10% of engineering design and supervision costs for incremental pond construction.

Construction expense--This expense includes temporary facilities, utilities, and equipment used during construction. The expense is calculated as a function of direct investment:

$$\text{Construction expense} = 0.25\ (\text{direct investment, excluding pond, in M\$})^{0.83} + 0.13\ (\text{pond direct investment, in M\$})^{0.83}$$

Contractor fees--Direct investment is also used to determine contractor fees:

$$\text{Contractor fees} = 0.096\ (\text{total direct investment in M\$})^{0.76}$$

Contingency--

Contingency is 20% of the sum of direct investment and indirect investment.

Other Capital Charges--

Other capital charges consist of an allowance for startup and modifications and interest during construction. The allowance for startup and modifications is 10% of the total fixed investment. Interest during construction is 12% of the total fixed investment. It is based on the simple interest which would be accumulated at 10% per year under the premise construction and expenditure schedule, assuming a 60% debt, 40% equity capital structure.

Land--

Total land requirements, including the waste disposal pond, are assumed to be purchased at the beginning of the project. A land cost of $3500 per acre is used.

Working Capital--

Working capital is money representing the cash flow of normal operation. In these premises, working capital is assumed to be the sum of 3 weeks of raw material costs, 7 weeks of direct costs, and 7 weeks of overhead costs.

Annual Revenue Requirements

Annual revenue requirements, based on a 7000 hour per year operating schedule, use the same operational profile and remaining life assumptions that are used in the power plant design premises. Costs are projected to 1980 dollars to represent a mid-1980 startup. The revenue requirements are divided into direct costs for raw materials and conversion and indirect costs for capital charges and overheads. Net revenue from byproduct sale is applied as a credit.

Direct Costs--

Projected direct costs for raw materials, labor, and utilities are shown in Table 9. Unit costs for steam and electricity are based on actual production costs, including fuel, labor, depreciation, rate base return on investment, and taxes. The charge for electricity used by the FGD system is based on its being a separate electrical consumer paying full price for service.

Maintenance costs are a function of the direct investment costs. They are adjusted for the size and complexity of the system, based on operating experience with the system or similar operations. The maintenance percentages are assumed to be constant over the life of the plant. Incremental pond maintenance is treated separately as a constant 3% of the incremental pond construction costs. Maintenance costs are shown in Table 10.

TABLE 9. PROJECTED 1980 UNIT COSTS FOR RAW MATERIALS, LABOR, UTILITIES, AND CREDITS FOR BYPRODUCTS

			$/unit
Raw Materials			
Na_2CO_3			103.00/ton
Coal			25.00/ton
Anthracite coal			60.00/ton
Agricultural limestone			15.00/ton
Filter aid			189.00/ton
Sand			7.50/ton
Labor			
Operating labor			12.50/man-hr
Analyses			17.00/man-hr
Mobile equipment			17.00/man-hr
Utilities			
Fuel oil (No. 6)			0.40/gal[b]
Steam			2.00/MBtu
Process water[a]			0.12/kgal
Boiler feedwater			0.92/kgal
	200 MW	500 MW	1,000 MW
Electricity	0.031/kWh	0.029/kWh	0.028/kWh
Credit for Byproducts			
Sulfur			40.00/ton[c]
Sulfuric acid (100%)			25.00/ton
Sodium sulfate			23.00/ton
Anthracite (spent)			25.00/ton

a. Varies according to process-dependent water requirements.
b. Because of the need to maintain comparability with previously published FGD studies, this unit cost was retained.
c. Short tons.

TABLE 10. OVERALL ANNUAL MAINTENANCE COSTS

Process	% of direct investment excluding pond construction[a]		
	200 MW	500 MW	1000 MW
Aqueous carbonate	8	7	6
Wellman-Lord/sulfuric acid	7	6	5
Wellman-Lord/Resox	7	6	5
Wellman-Lord/Allied Chemical coal/SO_2 reduction	7	6	5

a. Pond maintenance is estimated as 3% of the incremental pond construction cost.

Indirect Costs--

A summary of capital charges, based on regulated utility economics, is shown in Table 11. Straight-line depreciation is used, based on the remaining life of the power plant when the FGD system is installed. The allowance for interim replacement is increased from the usual average of about 0.35% because of the uncertain life span of FGD systems. The insurance allowance is based on FERC practice. Property taxes are included as 1.5% of the total depreciable capital investment. Cost of capital is based on the assumed capital structure.

Plant overhead is assumed to be 50% of the total conversion cost less utilities. Utilities are excluded to avoid over-changing, energy-intensive processes. Administrative overhead is assumed to be 10% of the operating labor and supervision cost. Marketing overhead is assumed to be 10% of the byproduct revenue.

Byproduct Credits

In the calculation of annual and lifetime economics, credit from the sale of byproducts is deducted from the revenue requirements to give the net revenue requirements of the FGD process. The byproduct credit applied is based on the selling price of the byproduct. An overhead of 10% of this credit is included in indirect costs for marketing expense. In addition to sulfur and sulfuric acid, byproduct credits are given for sodium sulfate produced by the Wellman-Lord process and spent anthracite produced by the Resox process are shown in Table 9.

Lifetime Revenue Requirements

Lifetime revenue requirements reflect the changing operating costs as operating time changes and the rate base declines because of depreciation. In addition, the revenue requirements can be discounted to reflect the time value of money. The lifetime revenue requirements in this study are calculated in the same manner as the annual revenue

requirements except that the capital charges are based on the declining undepreciated investment. The discounted lifetime revenue requirements are discounted at 11.6% to the initial year of operation.

TABLE 11. ANNUAL CAPITAL CHARGES FOR POWER INDUSTRY FINANCING

	Percentage of total depreciable capital investment		
Years remaining life	30	25	20
Depreciation (straight line, based on years remaining life of power unit)	3.3	4.0	5.0
Interim replacements (equipment having less than 30-year life)	0.7	0.4	-
Insurance	0.5	0.5	0.5
Property taxes	1.5	1.5	1.5
Total rate applied to original investment	6.0	6.4	7.0

	Percentage of unrecovered capital investment
Cost of capital (capital structure assumed to be 60% debt and 40% equity)	
Bonds at 10% interest	6.0
Equity[a] at 14% return to stockholder	5.6
Income taxes (Federal and State)[b]	5.6
Total rate applied to depreciation base	17.2[c]

a. Contains retained earnings and dividends.
b. Federal and State income taxes are assumed to have the same effect on capital cost as return on equity.
c. Applied on an average basis, the total annual percentage of original fixed investment for new (30-year) plants would be 6.0% + 1/2(17.2%) = 14.6%.

SYSTEMS ESTIMATED

The base-case FGD systems that serve as the bases of the cost estimates are conceptual designs prepared from process descriptions, material balances, flow and control diagrams, layout drawings, and equipment lists. The designs are developed from vendor information, industry experience, and the premises described in the previous section. For equitable comparison, an area-by-area format is used that divides each system into similar processing steps. Capital investment summaries are based on equipment lists that follow the area-by-area pattern.

Both the ACP and Wellman-Lord processes can be considered as absorption-regeneration systems that supply an end plant producing a marketable product. The ACP, with an integral reduction step, is provided with a Claus unit end plant because sulfur is the obvious economically desirable product. There are several feasible end plants for the Wellman-Lord process, however. The process incorporating the sulfuric acid end plant is included to represent an alternate byproduct and to provide a process using conventional technology for comparison with the coal reduction processes. With the exception of the Claus and sulfuric acid units, the general designs are based on vendor information. The designs represent late-1979 technology and design philosophy. They are based on the power plant conditions given in the premises, however, and do not represent a particular existing or planned installation.

AQUEOUS CARBONATE PROCESS

This is the first full economic evaluation of the ACP made by TVA, although TVA recently made a preliminary evaluation of the Rockwell International/Wheelabrator Fry open-loop process, which uses similar spray dryer technology (Burnett and O'Brien, 1980). The ACP used for the base-case conditions (a new 500-MW power plant using 3.5% sulfur coal) has four gas and reduction reactor trains and one regeneration train. Case variations follow a similar design except that the 200-MW case variations have only two gas trains. The flow diagram and the material balance are shown in Figure 1 and Table 12 respectively. The design drawings for the base case are shown in Figures 2-4.

The ACP is divided into nine operating areas: materials handling, gas handling, fly ash collection, SO_2 absorption and removal, reduction, off-gas treatment, carbonation, sulfur production, and sulfur storage and shipment. The equipment list, itemized by area, is shown in Table 13. The costs shown in Table 13 are purchase costs and do not include costs for erection.

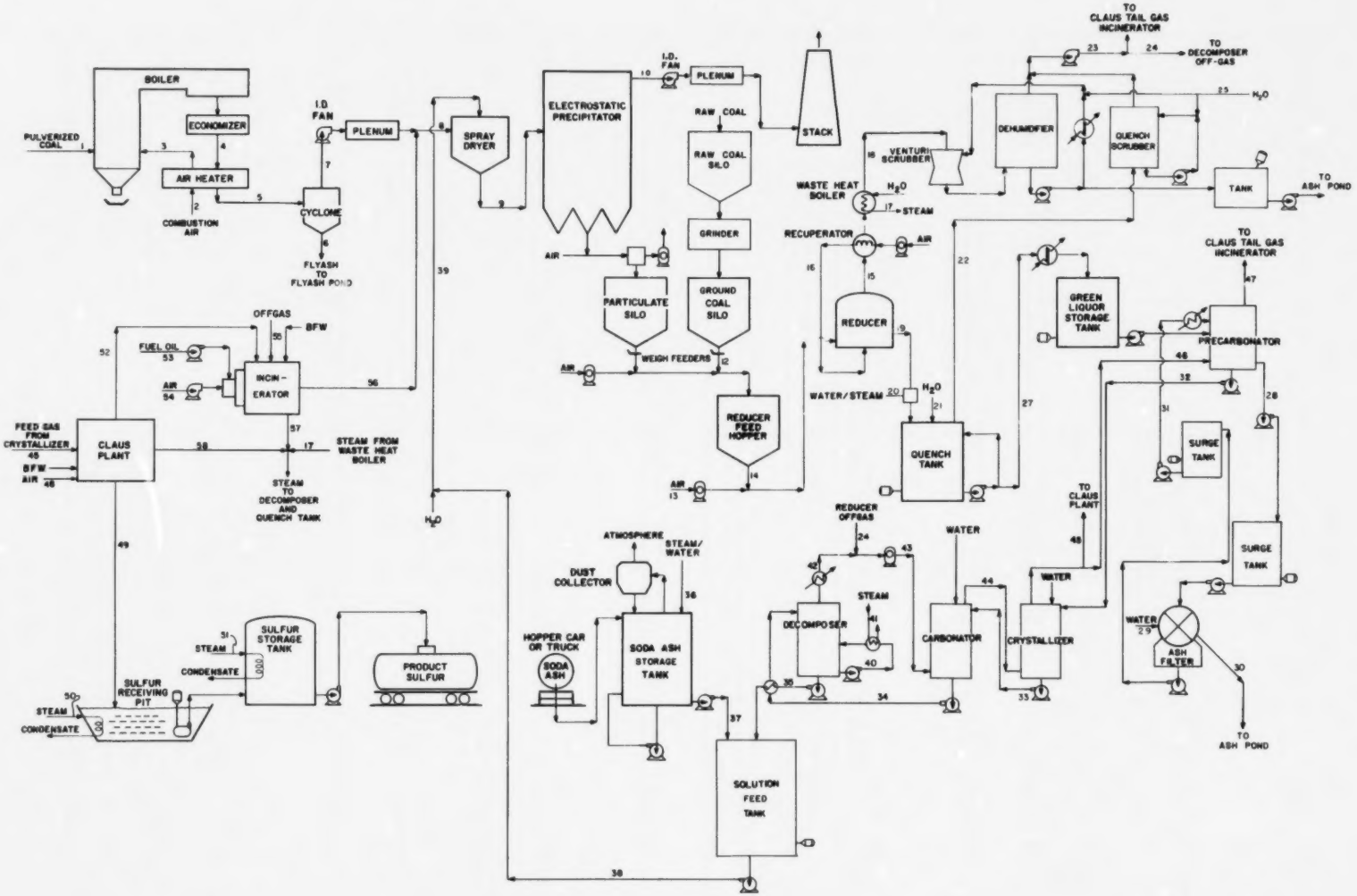

Figure 1. Aqueous carbonate process flow diagram.

TABLE 12. AQUEOUS CARBONATE PROCESS

BASE-CASE MATERIAL BALANCE

Stream No.	1	2	3	4	5
Description	Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to air heater	Gas to mechanical collectors
1 Total stream, lb/hr	428,600	4,546,200	4,101,800	4,516,100	4,960,400
2					
3					
4 sft^3/min (60°F)		1,005,000	966,700	958,000	1,056,000
5 Temperature, °F		80	535	705	300
6 Pressure, psia					
7 gpm					
8 Specific gravity					
9 pH					
10 Undissolved solids, %					

Stream No.	6	7	8	9	10
Description	Ash to ash pond	Gas to boiler plenum	Gas to spray dryer	Gas to electrostatic precipitator	Gas to stack
1 Total stream, lb/hr	46,600	4,913,800	5,034,000	5,283,200	5,204,900
2					
3					
4 sft^3/min (60°F)		1,056,000	1,077,500	1,113,700	1,113,700
5 Temperature, °F		300	300	170	170
6 Pressure, psia					
7 gpm					
8 Specific gravity					
9 pH					
10 Undissolved solids, %					

Stream No.	11	12	13	14	15
Description	Particulate to particulate silo	Coal to reducer feed hopper	Conveying air to reducer	Particulate-coal mixture to reducer	Reducer off-gas to recuperator
1 Total stream, lb/hr	78,300	14,500	8,000	92,800	79,900
2					
3					
4 sft^3/min (60°F)			1,727		17,100
5 Temperature, °F			80		1,800
6 Pressure, psia					
7 gpm					
8 Specific gravity					
9 pH					
10 Undissolved solids, %					

Stream No.	16	17	18	19	20
Description	Combustion air to reducer	Steam from waste heat boiler	Reducer off-gas to off-gas treatment area	Salt melt to quench tank	Steam to shatter jets
1 Total stream, lb/hr	40,100	24,100	79,900	61,000	12,600
2					
3					
4 sft^3/min, (60°F)	8,594		17,100		
5 Temperature, °F	1,000	377	560	1,800	377
6 Pressure, psia		190			190
7 gpm				102	
8 Specific gravity				1.2	
9 pH					
10 Undissolved solids, %					

(continued)

TABLE 12 (continued)

	Stream No.	21	22	23	24	25
	Description	Makeup water to quench tank	Quench off-gas to off-gas treatment	Off-gas from treatment area	Treatment area off-gas to carbonator	Makeup water to off-gas treatment area
1	Total stream, lb/hr	172,800	12,600	83,300	59,700	15,200
2						
3						
4	sft^3/min (60°F)		2,690	17,835	12,783	
5	Temperature, °F	80	220	100	100	80
6	Pressure, psia					
7	gpm	345				30
8	Specific gravity	1.0				
9	pH					
10	Undissolved solids, %					

	Stream No.	26	27	28	29	30
	Description	Chloride purge	Green liquor to storage tank	Green liquor to ash filter	Wash water to ash filter	Ash to disposal
1	Total stream, lb/hr	24,400	233,800	250,500	9,600	13,400
2						
3						
4	sft^3/min (60°F)					
5	Temperature, °F	100	220	110		
6	Pressure, psia					
7	gpm	49	389	501	19	
8	Specific gravity		1.2	1.2		
9	pH					
10	Undissolved solids, %					50

	Stream No.	31	32	33	34	35
	Description	Green liquor filtrate to precarbonator	Green liquor to crystallizer	Feed to carbonator	Feed to decomposer	Feed to solution storage tank
1	Total stream, lb/hr	246,600	249,200	252,200	257,000	235,300
2						
3						
4	sft^3/min, (60°F)					
5	Temperature, °F	110	110	110	130	254
6	Pressure, psia					
7	gpm	411	415	420	428	392
8	Specific gravity	1.2	1.2	1.2	1.2	1.20
9	pH					
10	Undissolved solids, %					

	Stream No.	36	37	38	39	40
	Description	Water to raw material storage tank	Makeup absorbent solution to solution storage tank	Rich absorbent solution to spray dryer	Absorbent solution to spray dryer	Feed to reboiler
1	Total stream, lb/hr	6,310	9,400	244,700	249,200	1,933,300
2						
3						
4	sft^3/min, (60°F)					
5	Temperature, °F	80				254
6	Pressure, psia					
7	gpm	13	16	489	498	3,219
8	Specific gravity	1.0	1.0	1.2	1.2	1.20
9	pH					
10	Undissolved solids, %					

(continued)

TABLE 12 (continued)

	Stream No.	41	42	43	44	45
	Description	Steam to decomposer reboiler	Decomposer off-gas to carbonator	Combined off-gas to carbonator	Carbonator off-gas to crystallizer	Crystallizer off-gas to Claus unit
1	Total stream, lb/hr	37,700	21,700	81,400	76,600	36,800
2						
3						
4	sft^3/min (60°F)		3,253	15,057	15,152	11,003
5	Temperature, °F	377	90	118	110	118
6	Pressure, psia	190		37	32	22
7	gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	46	47	48	49	50
	Description	Crystallizer off-gas to precarbonator	Precarbonator off-gas to incinerator	Air to Claus unit	Sulfur to receiving pit	Steam to sulfur receiving pit
1	Total stream, lb/hr	36,800	17,500	4,000	10,400	23
2						
3						
4	sft^3/min (60°F)	11,003	4,060	871		
5	Temperature, °F	118	100	80	330	377
6	Pressure, psia	22				190
7	gpm					
8	Specific gravity				10	
9	pH				2.07	
10	Undissolved solids, %					

	Stream No.	51	52	53	54	55
	Description	Steam to sulfur storage tank	Claus tail-gas to incinerator	Fuel oil to incinerator	Combustion air to incinerator	Off-gas to incinerator
1	Total stream, lb/hr	2,600	30,400	2,500	46,200	41,100
2						
3						
4	sft^3/min (60°F)		6,518		9,890	8,792
5	Temperature, °F	377	275		275	100
6	Pressure, psia	190				
7	gpm			5		
8	Specific gravity			0.91		
9	pH					
10	Undissolved solids, %					

	Stream No.	56	57	58		
	Description	Incinerator tail-gas to flue gas ducts	Steam from incinerator	High pressure steam from Claus unit		
1	Total stream, lb/hr	120,200	20,800	36,200		
2						
3						
4	sft^3/min (60°F)	23,785				
5	Temperature, °F	600	377	377		
6	Pressure, psia		190	190		
7	gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

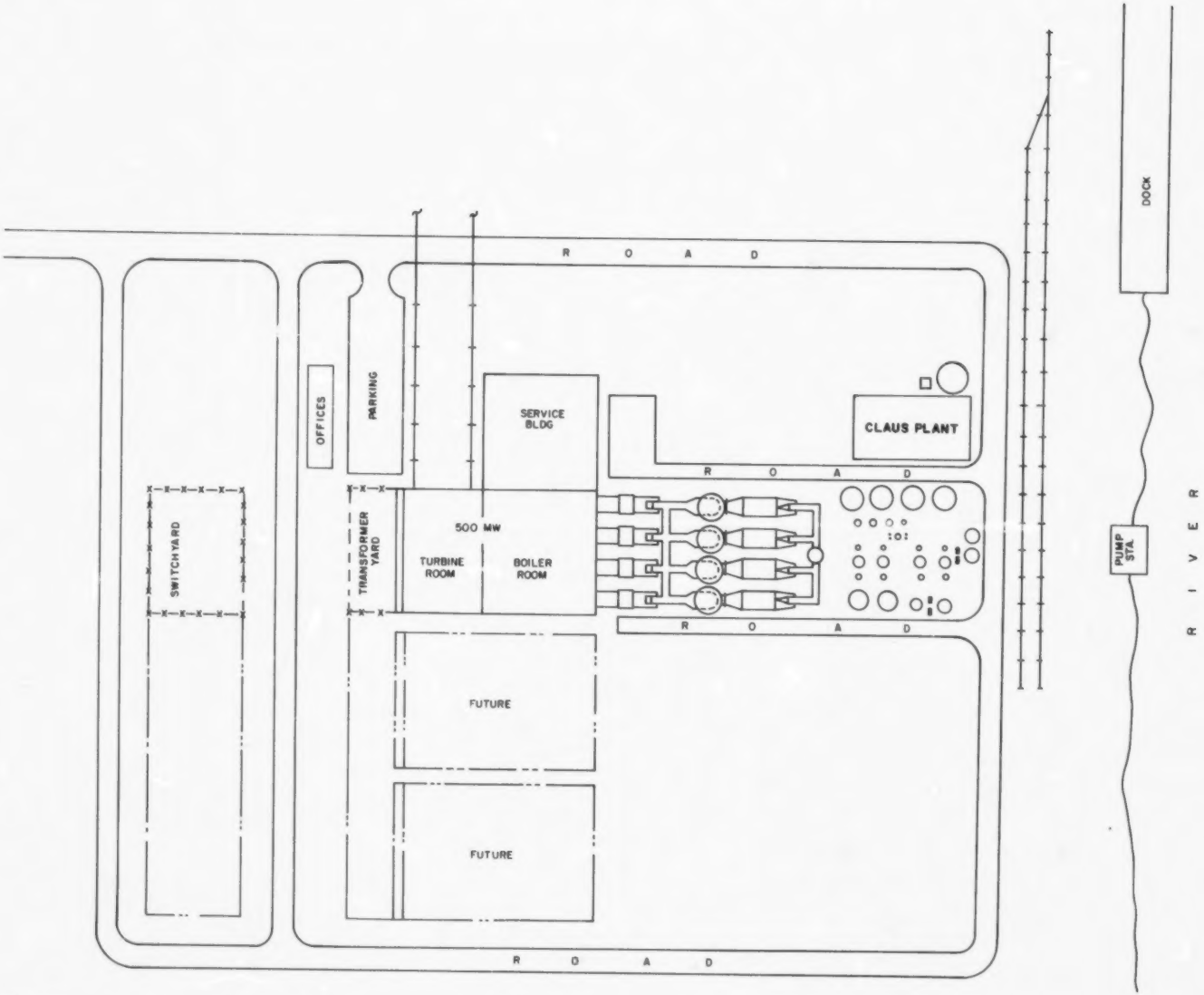

Figure 2. Aqueous carbonate process plot plan.

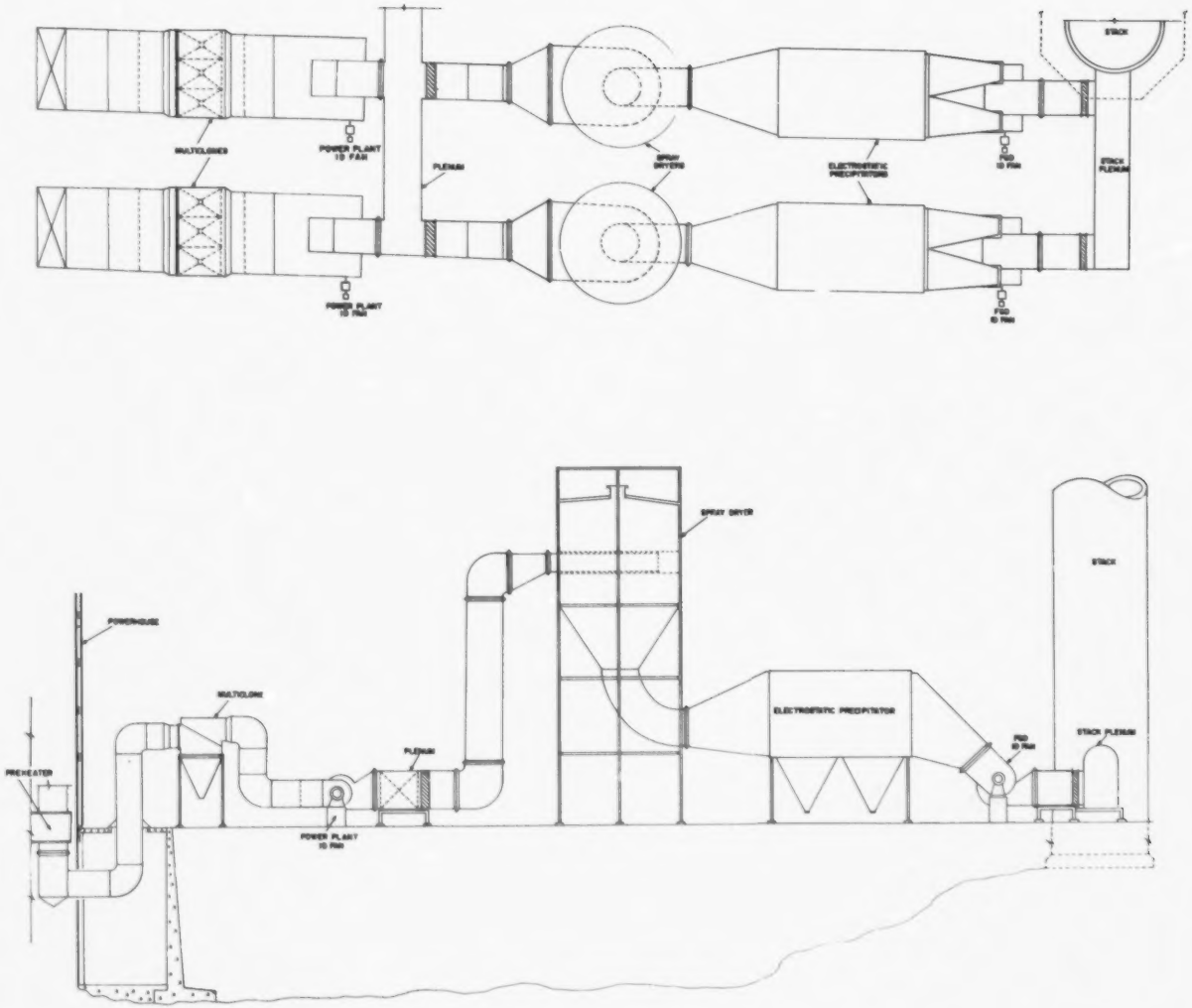

Figure 3. Aqueous carbonate process elevation drawing.

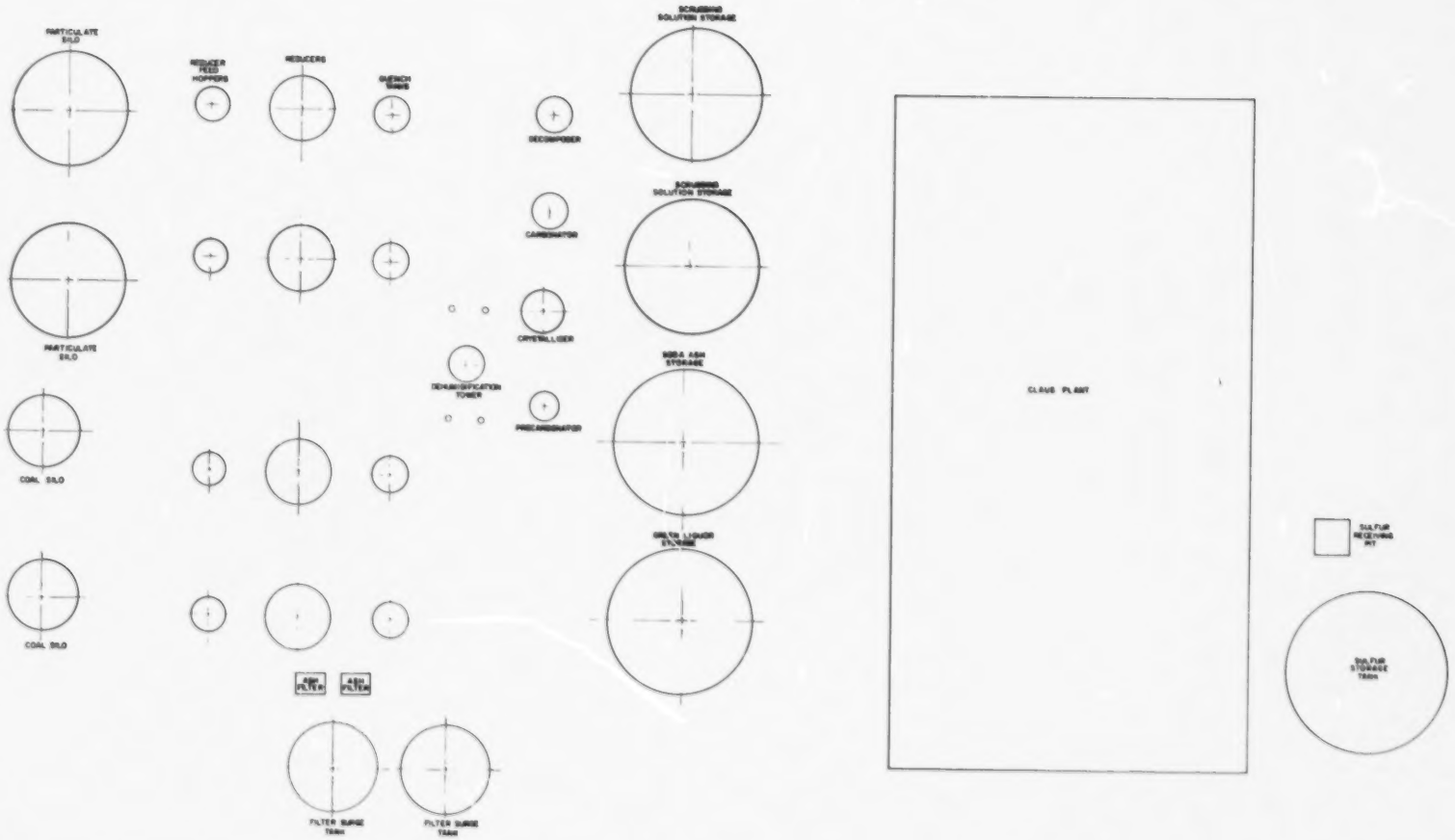

Figure 4. Aqueous carbonate process regeneration area layout drawing.

TABLE 13. AQUEOUS CARBONATE PROCESS

BASE-CASE EQUIPMENT LIST

Area 1--Materials Handling

Item	No.	Description	Total material cost, 1979 $
1. Car shaker	1	Top mounting with crane, 20 hp shaker, 7-1/2 hp crane	19,900
2. Tank, soda ash storage	1	40 ft dia x 40 ft high, 376,000 gal, w/cover, carbon steel, insulated (30 day storage)	71,600
3. Pump, soda ash recirculating	2	Centrifugal, 16 gpm, 50 ft head, 1/2 hp, carbon steel, insulated (1 operating, 1 spare)	3,300
4. Pump, soda ash feed	2	Centrifugal, 16 gpm, 50 ft head, 1/2 hp, carbon steel, insulated (1 operating, 1 spare)	3,300
5. Dust collecting system	1	Bag filter, polypropylene bag, 4000 aft^3/min, automatic shaker system	12,200
Subtotal			110,300

Area 2--Gas Handling

Item	No.	Description	Total material cost, 1979 $
1. Fans	4	Induced draft, 337,300 aft^3/min 15 in. static head, 875 rpm, 1250 hp, fluid drive, double width, double inlet	812,000
Subtotal			812,000

(continued)

TABLE 13 (continued)

Area 3--Fly Ash Collection

Item	No.	Description	Total material cost, 1979 $
1. Mechanical collector	4	Multiclone, 85% collection efficiency, 30-1/2 ft x 10-1/2 ft x 25-1/2 ft high, cast iron shell with abrasion resistant tubes	337,200
Subtotal			337,200

Area 4--SO_2 Absorption and Removal

Item	No.	Description	Total material cost, 1979 $
1. Spray dryer	4	42 ft dia x 65 ft high with 4 (1 spare) rotary atomizers, carbon steel	2,898,000
2. Electrostatic precipitator	4	99.34% collection efficiency, 350 ft^2 SCA	2,282,000
3. Conveyor, particulate matter to silo	1	Pneumatic, negative pressure conveying system, 35 ton/hr, 200 hp	118,100
4. Silo, particulate	2	32 ft dia x 32 ft straight side, 25,750 ft^3, 60° slope, carbon steel (12-hour capacity each)	58,000
Bin activator	2		22,700
5. Tank, solution feed	2	37-1/2 ft dia x 38 ft high, 313,900 gal, w/cover, carbon steel, neoprene lined (12-hour capacity each)	150,200
6. Agitator, solution feed tank	2	Side mounted, 150 in. dia, 150 hp, neoprene coated	316,000
7. Pump, solution feed	12	Centrifugal, 400 gpm, 250 ft. head, 50 hp, carbon steel, neoprene lined (8 operating, 4 spares)	102,600
Subtotal			5,947,600

(continued)

TABLE 13 (continued)

Area 5--Reduction

Item	No.	Description	Total material cost, 1979 $
1. Feeder, raw coal retrieval	2	Vibrating pan, 12 in. wide x 48 in. long, 35 ton/hr, 0.5 hp	3,200
2. Conveyor, raw coal retrieval	1	Belt, 14 in. wide x 1500 ft long, 30 ft lift, 10 hp, 32 ton/hr, 200 ft/min	280,000
3. Silo, raw coal	1	20 ft dia x 24 ft straight side, 7,500 ft^3, 60° slope, carbon steel (24-hour capacity)	13,200
4. Grinding mill	2	Giant roller mill system (includes grinding and dust control equipment), 23 tons/hr	536,700
5. Elevator, ground coal feed	1	Continuous bucket, 12 in. x 7 in. x 11-3/4 in., 3 hp, 50 ft lift, 23 ton/hr, 150 ft/min	9,500
6. Silo, coal	1	24 ft dia x 24 ft straight side, 10,900 ft^3, 60° slope, carbon steel (24-hour capacity)	16,700
Bin activator	1		11,400
7. Feeder, coal silo	1	Vibrating pan, 10 in. wide x 36 in. long, 7.5 ton/hr, 1/2 hp	900
8. Feeder, particulate silo	1	Vibrating pan, 24 in. wide x 36 in. long, 35 ton/hr, 2 hp	3,200
9. Conveyor, reducer feed transfer	1	Pneumatic, positive pressure conveying system, 42 ton/hr, 200 hp	143,000
10. Hopper, reducer solids feed	4	9 ft dia x 9 ft straight side, 575 ft^3, carbon steel (1-hour capacity each)	6,000
11. Conveyor, reducer solids feed	4	Pneumatic, positive pressure conveying system, 10.5 ton/hr, 50 hp	148,800
12. Reducer air system	4	Oil-free compressors, 3,500 ft^3/min, 350 hp (3 operating, 1 spare)	416,000

(continued)

TABLE 13 (continued)

Item	No.	Description	Total material cost, 1979 $
13. Reducer	4	18 ft dia x 34 ft high Monofrax A® and Alfrax® lined carbon steel, with air feed and solids feed nozzles and preheat burner	3,192,400
14. Recuperator, reducer air	4	Shell and tube heat exchanger, 200 ft^2, 304 stainless steel	40,000
15. Soot blowers	40	Air, retractable	260,000
16. Waste heat boiler	4	Shell and tube heat exchanger, 410 ft^2, carbon steel	59,300
17. Quench tank	4	10 ft dia x 14 ft high, 5,900 gal operating capacity, carbon steel with 304 stainless steel overlay in gas space	18,900
18. Agitator, quench tank	4	Side entering, 15 hp, neoprene coated	10,500
19. Pump, quench tank recirculating	8	Centrifugal, 100 gpm, 100 ft head, 7-1/2 hp, carbon steel, neoprene lined (4 operating, 4 spares)	29,200
Subtotal			5,198,900

Area 6--Off-Gas Treatment

Item	No.	Description	Total material cost, 1979 $
1. Scrubber, reducer off-gas	4	Variable throat venturi, 3950 sft^3/min, 40 in. ΔP	111,300
2. Dehumidification tower	1	Packed column, 10 ft dia x 15 ft high, 10 ft of 2-in. Rashig rings, 316 stainless steel shell	17,600
3. Pump, tower recirculating	2	Centrifugal, 500 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
4. Quench off-gas scrubber	4	Tray tower, 2 ft dia x 7 ft high, 304 stainless steel	12,000

(continued)

TABLE 13 (continued)

Item	No.	Description	Total material cost, 1979 $
5. Fan, quench off-gas	4	Centrifugal, 600 aft^3/min, 20 in. static head, 5 hp, carbon steel, asphalt coated	7,200
6. Pump, quench scrubber recirculating	4	Centrifugal, 150 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (2 operating, 2 spares)	18,200
7. Cooler, recirculating water	2	Plate and frame type heat exchanger, 3200 ft^2, carbon steel with titanium plates (1 operating, 1 spare)	132,600
8. Fans, reducer off-gas	3	Centrifugal, 9000 aft^3/min, 60 in. static head, 125 hp, 304 stainless steel (2 operating, 1 spare)	43,200
9. Tank, chloride-ash purge	1	10 ft dia x 10 ft high, 5870 gal, carbon steel, neoprene lined (30-minute capacity)	4,700
10. Agitator, chloride-ash tank	1	40 in. dia, 7.5 hp, neoprene coated	12,000
11. Pump, chloride-ash disposal	2	Centrifugal, 83 gpm, 100 ft head, 10 hp (1 operating, 1 spare)	1,800
Subtotal			369,700

Area 7--Carbonation

Item	No.	Description	Total material cost, 1979 $
1. Tank, green liquor storage	1	40 ft dia x 30 ft high, 282,000 gal, w/cover, carbon steel epoxy-lined (12-hour capacity)	49,100
2. Agitator, green liquor storage tank	1	Side entering, 75 hp, neoprene coated	130,000

(continued)

TABLE 13 (continued)

Item	No.	Description	Total material cost, 1979 $
3. Cooler, green liquor	2	Plate and frame type heat exchanger, 3600 ft^2, carbon steel with titanium plates (1 operating, 1 spare)	142,000
4. Pump, pre-carbonator feed	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
5. Precarbonator	1	Sieve tray column, 8 ft dia x 60 ft high, 316L stainless steel	63,900
6. Pump, filter feed surge tank	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
7. Tank, filter feed surge	1	25 ft dia x 26 ft high, 96,000 gal, w/cover, carbon steel, neoprene-lined (4-hour capacity)	34,100
8. Agitator, filter feed surge tank	1	Side entering, 50 hp, neoprene coated	68,000
9. Pump, filter feed	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
10. Filter	2	Rotary precoat type, 6 ft dia x 8 ft long, 151 ft^2, 40 hp, 316 stainless steel	178,600
11. Pump, filtrate recirculating	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
12. Tank, filtrate surge	1	25 ft dia x 26 ft high, 96,000 gal, w/cover, carbon steel, neoprene-lined (4-hour capacity)	34,100
13. Agitator, filtrate surge tank	1	Side entering, 50 hp, neoprene coated	68,000
14. Pump, pre-carbonator recycle	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100

(continued)

TABLE 13 (continued)

Item	No.	Description	Total material cost, 1979 $
15. Cooler, precarbonator interstage	2	Plate and frame type heat exchanger, 4050 ft^2, carbon steel with titanium plates (1 operating, 1 spare)	155,600
16. Pump, crystallizer feed	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
17. Crystallizer	1	Sieve tray column, 12 ft dia x 58 ft high, 316 stainless steel	83,700
18. Pump, carbonator feed	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
19. Cooler, crystallizer effluent	2	Plate and frame type heat exchanger, 1500 ft^2 carbon steel with titanium plates (1 operating, 1 spare)	80,000
20. Carbonator	1	Sieve tray column, 10 ft dia x 58 ft high, 316 stainless steel	74,600
21. Pump, decomposer feed	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
22. Decomposer	1	Sieve tray column, 10 ft dia x 62 ft high, Incoloy 800 lined with carbon steel shell	79,900
23. Pump, mixing tank feed	2	Centrifugal, 400 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
24. Cooler, decomposer effluent	2	Plate and frame type heat exchanger, 2870 ft^2, carbon steel with titanium plates (1 operating, 1 spare)	123,000
25. Pump, decomposer reboiler feed	2	Centrifugal, 2600 gpm, 60 ft head, 100 hp, carbon steel, neoprene lined (1 operating, 1 spare)	22,100

(continued)

TABLE 13 (continued)

	Item	No.	Description	Total material cost, 1979 $
26.	Reboiler, decomposer	2	Shell and tube heat exchanger, 4400 ft^2, 304 stainless steel shell with Carpenter alloy 20 tubes (1 operating, 1 spare)	226,300
27.	Condenser, decomposer	1	Shell and tube heat exchanger 2250 ft^2, 304 stainless steel	41,900
28.	Compressor, process off-gas	3	Centrifugal, 6200 sft^3/min, 700 hp, 304 stainless steel (2 operating, 1 spare)	501,000
	Subtotal			2,307,800

Area 8--Sulfur Production

	Item	No.	Description	Total material cost, 1979 $
1.	Claus unit	1	3-stage Claus unit complete, 96% efficient, 123 tons of sulfur/day (battery limits cost)	3,045,000
	Subtotal			3,045,000

Area 9--Sulfur Storage

	Item	No.	Description	Total material cost, 1979 $
1.	Pit, sulfur receiving	1	10 ft long x 10 ft wide x 10 ft high, 1000 ft^3, w/cover, carbon steel, insulated	5,500
	Heater	1	Steam, 100 ft^2, 400 ft of 1-in. chedule 40, carbon steel	700
2.	Pump, sulfur transfer	2	Centrifugal, 12 gpm, 100 ft head, 2 hp, steam traced and insulated, carbon steel (1 operating, 1 spare)	2,100

(continued)

TABLE 13 (continued)

	Item	No.	Description	Total material cost, 1979 $
3.	Tank, sulfur storage	1	45 ft dia x 46 ft high, 547,300 gal, w/cover, carbon steel, insulated	94,700
	Heater	1	Steam, 300 ft^3, 1200 ft of 1-in. Schedule 40, carbon steel	2,100
4.	Pump, sulfur shipping	2	Centrifugal, 60 gpm, 100 ft head, 5 hp, steam traced and insulated, carbon steel (1 operating, 1 spare)	5,000
	Subtotal			110,100

Materials Handling Area

Dry soda ash containing 99.8% Na_2CO_3 is unloaded from pneumatic-equipped transporters and stored as a wet slurry in a covered tank with a 30-day capacity. Storage of sodium carbonate in slurry form is well known in the chemical industry and is economically advantageous because the equipment needed for slurry storage is significantly smaller. Dry soda ash with a bulk density of 35 lb/ft^3 is transformed into a wet sodium carbonate monohydrate with a bulk density of 56 lb/ft^3, thereby decreasing the volume needed to store equal weights of the material. The storage tank is insulated to keep the contents above 105°F to avoid the formation of the heptahydrate and decahydrate, which are difficult to dissolve. The monohydrate, however, readily dissolves. Maintenance of tank temperature is not difficult since a considerable amount of heat is evolved in the charging process by the heats of solution and monohydration. The transition from water to a slurry creates a temperature rise of 60°F. The saturated solution above the slurry is 32% by weight Na_2CO_3. As this solution is removed to supply the system makeup requirements, process condensate at about 140°F is sparged into the tank bottom to dissolve some $Na_2CO_3 \cdot H_2O$ and replenish the Na_2CO_3 solution. The initial temperature rise and the addition of 140°F condensate eliminate the need for an external heat supply to the insulated tank.

Gas Handling and Fly Ash Collection Areas

This area consists of all flue gas ductwork between the power plant ID fans and the stack plenum. The four power plant ID fans discharge into a common plenum that is connected by individual ducts to each of the four spray dryers. The spray dryers are connected individually to the four ESP's. Each ESP is connected to a downstream ID fan, which compensates for the 15 in. H_2O pressure drop in the FGD system. The ID fans discharge into the stack plenum. All ductwork between the power plant ID fans and the stack plenum, and the FGD ID fans, is included in the FGD costs.

In addition, four cyclone collectors, situated between the boiler air heaters and the power plant ID fans, are included in the FGD costs. These collectors remove 85% of the fly ash to facilitate subsequent absorbent processing. Fly ash handling and disposal costs are not included in FGD costs.

SO_2 Absorption and Removal Areas

The ACP uses four trains of spray dryer absorbers and ESP's. The spray dryers are carbon steel, 42-foot diameter, 65-foot high, conical-bottom vessels. Four rotary-disk atomizers, driven by vertically mounted motors, are installed in the top of each spray dryer. Under normal conditions, three atomizers are operated and the fourth serves as a spare. The absorbent solution is pumped from the solution feed tank at a concentration of about 23% Na_2CO_3. This is diluted with water at a rate controlled by the SO_2 content of the cleaned flue gas. The diluted solution is pumped to the atomizers at a rate controlled by the temperature of the flue gas leaving the spray dryer.

The flue gas enters the top of the spray dryer at 300°F through a distribution plenum and passes downward through the atomized Na_2CO_3 solution. The SO_2 and HCl in the flue gas react with the Na_2CO_3 to form Na_2SO_3, Na_2SO_4, and NaCl, which, with the unreacted Na_2CO_3, form particulate matter as the liquid in the Na_2CO_3 solution is evaporated. The sodium-salt particulate matter, along with the fly ash remaining in the flue gas, is carried out of the bottom of the spray dryer in the flue gas, which is cooled to 170°F by evaporation of the liquid.

The flue gas passes through an ESP designed for a collection efficiency of 99.34% with a specific collecting area (SCA) of 350 ft^2 per $kaft^3$/min of flue gas. The cleaned flue gas passes through the FGD ID fan and enters the stack plenum at 170°F without reheating. The particulate matter from the four ESP's is transferred to two carbon-steel particulate matter silos in a negative-pressure pneumatic conveying system. Each silo has a capacity of 12 hours.

Reduction Area

In this area the particulate matter is blended with ground power plant coal and the sulfur salts are reduced to Na_2S in four trains of molten salt reducers. The melt, containing Na_2S, other sodium compounds, and residual solids, is quenched and dissolved for further processing. The off-gas is sent to the off-gas processing area.

Coal from the power plant stockpile is conveyed to a raw coal silo. The coal is ground to 80% to pass 200 mesh in two roller mills and conveyed by bucket elevator to a 24-hour-capacity ground coal silo.

The sodium-salt particulate matter and the ground coal are metered with weigh feeders into a pneumatic conveying system and transferred to the four reducer feed hoppers. The feed rate of the sodium-salt particulate matter is based on the $CO:CO_2$ ratio in the reducer off-gas. The coal feed rate is based on the reducer melt temperature. For the base case, a total of 78,300 lb/hr of particulate matter and 14,500 lb/hr of coal are fed to the four reducers.

Each reducer consists of a cylindrical carbon steel vessel 18 feet in diameter and 34 feet high. The bottom half of the reducer is lined with 6 inches of Alfrax 66® overlain by 15 inches of Monofrax A®, both alumina refractory materials. The bottom of the reducer is a truncated cone containing 3 solids injection nozzles and 16 combustion air injection nozzles. The reduced melt (sometimes called smelt) is withdrawn through overflow nozzles about 10 feet from the bottom. The off-gas is withdrawn through vents in the top of the reducer. Each reducer is equipped with a steam-water shatter jet and quench tank for the melt and a recuperator and waste heat boiler for the off-gas. The recuperator is equipped with fuel-oil heating equipment to heat combustion air during startup and downtimes. The particulate matter - coal mixture is discharged from the reducer feed hopper through rotary air locks into a pneumatic conveying system, which blows it into the reducer through the injection nozzles. Simultaneously, combustion air, heated to 1000°F by the reducer off-gas,

is injected through the air nozzles. The molten bed is maintained at 1800°F by control of the combustion air and coal rates. The reduced melt from the overflow nozzles flows by gravity to the quench tank. Steam and water are injected into the overflow line between the reducer and the quench tank to solidify and shatter the melt. The shattered melt is dissolved by addition of water to the agitated quench tank to form green liquor.

The green liquor contains about 24% total solids, of which about 40% is Na_2S, about 15% each is Na_2CO_3, Na_2SO_4, and Na_2SiO_3, 6% is NaCl (the equilibrium recycle level), and the rest is fly ash and other insoluble material.

The CO_2-rich off-gas from the reducer is passed through a recuperator, where it is cooled to 1000°F in heating the reducer combustion air, and through a waste heat boiler, where it is cooled to 560°F in producing steam. The off-gas is then sent to the off-gas treatment area.

Off-Gas Treatment Area

The reducer off-gas is about one-half N_2 and one-third CO_2 and contains about 2% particulate matter (NaCl, Na_2CO_3, Na_2SO_4). The off-gas is scrubbed with water in a variable-throat venturi and dehumidified in a packed column. Water withdrawn from the bottom of the dehumidifier is pumped through a water-cooled plate and frame heat exchanger and into the scrubber. A purge stream containing the particulates removed from the off-gas is discharged to a tank from which it is pumped to the ash pond. In addition to cooling and cleaning the off-gas, this treatment also serves as a chloride purge mechanism. About one-third of the chlorides entering the reducer leave it in the off-gas and are removed from the system in the purge stream. A separate scrubber is used for each reactor. One dehumidifier is used for all four scrubbers. The quench tank off-gas, consisting of steam and reducer off-gas, is scrubbed with water in a tray tower. A separate scrubber is used for each of the four quench tanks. The treated gas is combined with the treated reducer off-gas. About two-thirds of the treated gas is returned to the carbonation process. The remainder is sent to the Claus unit incinerator.

Carbonation Area

In this area the green liquor is processed in a series of steps that produce H_2S and Na_2CO_3. Reducer off-gas from the off-gas treatment area and decomposer off-gas are used as the CO_2 source. A single train of process equipment is used.

Green liquor from the green liquor storage tank is first treated in the precarbonator with a portion of the product H_2S to form NaHS. The precarbonator is a sieve tray column 8 feet in diameter and 60 feet high, which operates at 100°F and atmospheric pressure. The H_2S passes upward, countercurrently to the green liquor flow. The precarbonator off-gas is piped to the Claus unit incinerator. A sidestream is withdrawn from the precarbonator and filtered in a rotary filter to remove

fly ash that is in the particulate matter feed to the reducer and the solids from the reducer coal. This sidestream also serves to control the precarbonator temperature. The filtrate is passed through a plate and frame, water-cooled heat exchanger before being returned to the precarbonator. Surge tanks are included in the filter loop to allow filter downtime for precoating. The filter cake is disposed of in the power plant ash pit. The precarbonator bottoms, a solution of about 30% solids consisting of about 55% NaHS, 5% NaCl, and the remainder $NaHCO_3$, Na_2CO_3, and Na_2SO_4, are pumped to the crystallizer and carbonator.

The crystallizer and carbonator, both sieve tray columns 58 feet high and 12 and 10 feet in diameter, respectively, are used to treat the NaHS with CO_2 to form $NaHCO_3$ and H_2S. The gas stream, consisting of the combined treated reactor off-gas and decomposer off-gas streams, containing about 54% CO_2, flows countercurrently to the liquid stream through the carbonator and crystallizer. Small quantities of water are added to each vessel to control concentrations. The crystallizer operates at 118°F and 7 psig; the carbonator operates at 110°F and 17 psig. Conversion is roughly [illegible] in each vessel. The crystallizer off-gas consists of about 30% H_2S, 40% N_2, and 16% CO_2 with some H_2O, CO, and O_2. Half of this stream is sent to the Claus unit and half is sent to the precarbonator. The bottoms from the carbonator contain about 32% solids composed of about 87% $NaHCO_3$, 9% Na_2SO_4, and 4% N[illegible]. The carbonator bottoms are pumped to the decomposer through a heat exchanger to exchange heat with the decomposer bottoms.

The decomposer is also a sieve tray column, 10 feet in diameter and 62 feet high, in which the $NaHCO_3$-rich liquid is heated at 254°F at 12 psig to form Na_2CO_3. The liquid is heated by circulation through a shell and tube heat exchanger. The bottoms, containing about 28% solids composed of 82% Na_2CO_3, 13% Na_2SO_4, and 5% NaCl, are pumped to the solution feed tank for reuse. The overhead vapor, which is almost all CO_2, is combined with the reducer off-gas for use in the carbonator and crystallizer.

Sulfur Production and Storage Areas

The sulfur production area includes a battery limits Claus unit. This unit is a conventional three-stage Claus plant consisting of a reaction furnace and waste-heat boiler, three converter and condenser stages, a coalescer to strip sulfur from the off-gas, and an oil-fired tail gas incinerator. The incinerator is also used to burn excess reactor off-gas and precarbonator off-gas, neither of which contains appreciable combustibles. For the base case, the flow rate to the Claus unit is about 37,000 lb/hr of gas containing about 30% H_2S. Conversion is 96%, producing about 10,000 lb/hr of sulfur. About 30,000 lb/hr of Claus unit off-gas and 40,000 lb/hr of ACP off-gas are burned in the incinerator, returning about 430 lb/hr of sulfur to the flue gas. The Claus plant sulfur is pumped to a steam-heated receiving pit 10 feet square and 10 feet deep, from which it is pumped to a steam-heated, 30-day-capacity storage tank.

WELLMAN-LORD PROCESS

TVA previously evaluated the Wellman-Lord process in 1975 (McGlamery et al., 1975) using the Allied Chemical methane (natural gas) reduction process for production of sulfur. The design and economic premises upon which the evaluations are based have been updated since 1975. There have also been significant design changes in the Wellman-Lord process since the 1975 study. The soda ash is stored as a slurry instead of as a dry solid. A prescrubber has been added to prevent chloride buildup in the absorbent liquid. All stainless steel is now 316 SS rather than 304 SS. The absorber design is now based on cast concrete construction. A filter has been added to remove residue particulate matter from the scrubber effluent. The use of an antioxidant to control sulfate formation has been discontinued and sulfate formation is minimized by control of scrubbing conditions. Sulfate formation has been reduced and only 17% of the scrubber effluent is processed to remove sulfates. This is now done in a steam-heated evaporator rather than a chiller-crystallizer. The 17% rate is based on design guarantees for the Northern Indiana Public Service Company's Mitchell Station unit. Recent operating experience there, and at the Public Service of New Mexico's San Juan Station, has shown lower sulfate formation rates. For the base-case conditions used in this study, the soda ash consumption is 1800 lb/hr and the dryer product is 2300 lb/hr. Based on the operating data, the rates would be 1500 lb/hr of soda ash and 1900 lb/hr of dryer product.

Basically, the same Wellman-Lord process is used for all three end-plant cases. Minor changes in process design and overall flow rates are required to satisfy the requirements of the particular end plants. In particular, the SO_2:H_2O ratio of the product gas differs because of end-plant process requirements and the quantity of SO_2 in the product gas differs because of different quantities of SO_2 in the tail gas returned to the Wellman-Lord system. The Wellman-Lord process for the sulfuric acid case is described in full. This description also applies to the Resox® and Allied Chemical coal/SO_2 reduction processes except for the process-specific differences described for these two processes.

WELLMAN-LORD/SULFURIC ACID PROCESS

This process incorporates a conventional contact sulfuric acid unit with the Wellman-Lord process. The base-case process (a new 500-MW power plant using 3.5% sulfur coal) has four gas trains and, with the exception of the evaporator section, a single regeneration train. Case variations follow a similar design except that the 200-MW case variations have two gas trains. A single, appropriately sized, sulfuric acid unit is used for all cases.

The base-case Wellman-Lord process flow diagram is shown in Figure 5. The material balance shown in Table 14 applies to all three processes, with the exceptions for Wellman-Lord/Resox and Wellman-Lord/Allied processes specified later in the discussion of these processes. The

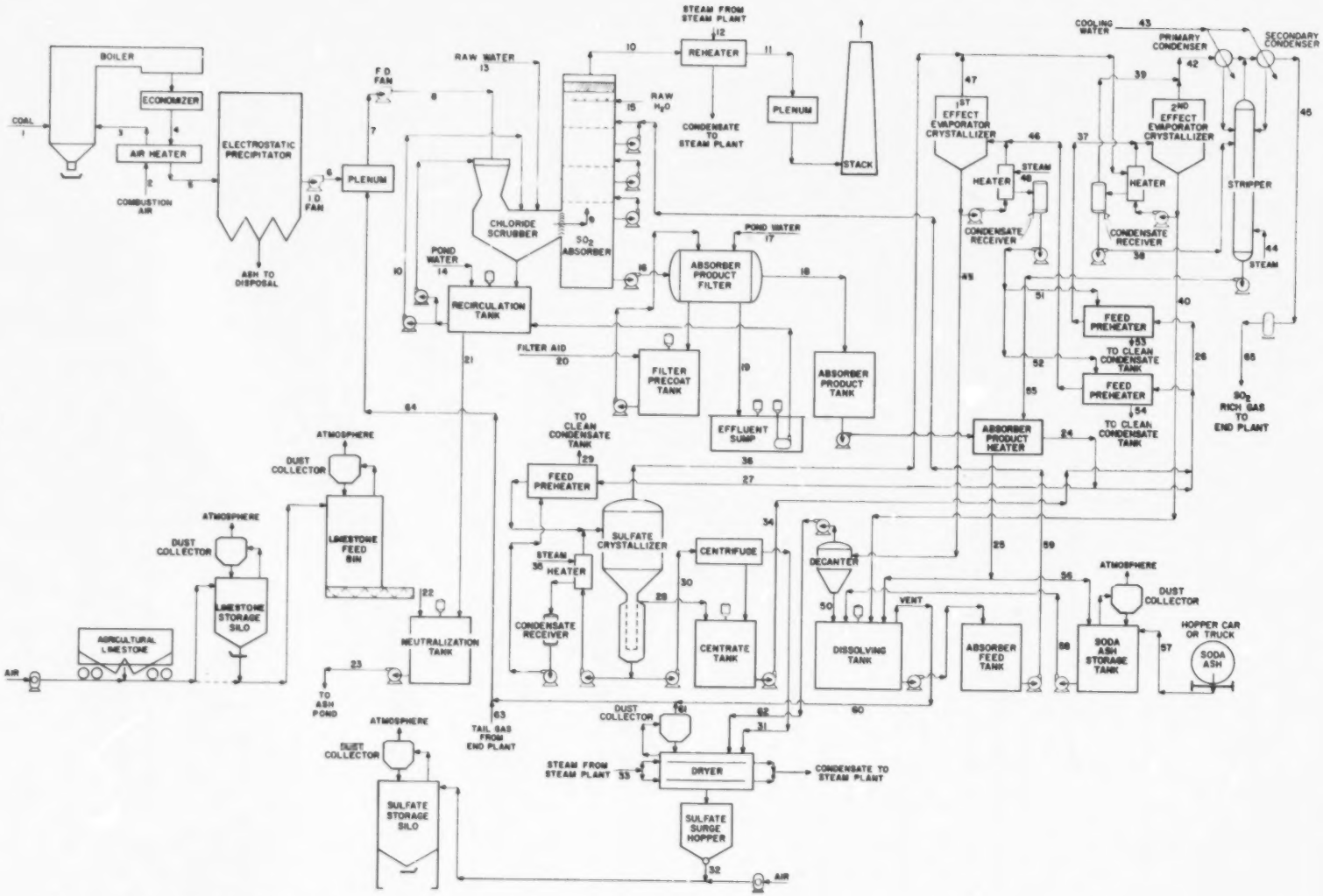

Figure 5. Wellman-Lord process flow diagram.

TABLE 14. WELLMAN-LORD/SULFURIC ACID PROCESS

BASE CASE MATERIAL BALANCE

	Stream No.	1	2	3	4	5
	Description	Coal to boiler	Combustion air to air heater	Combustion air to boiler	Gas to air heater	Gas to electrostatic precipitator
1	Total stream, lb/hr	428,600	4,546,200	4,101,800	4,516,100	4,960,400
2	sft^3/min (60°F)		1,005,000	906,700	958,000	1,056,000
3	Temperature, °F		80	535	705	300
4	Pressure, psia (in. WG)					
5	gpm					
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	6	7	8	9	10
	Description	Gas to plenum	Gas to FD fan	Gas to chloride scrubber	Gas to absorber	Gas to reheater
1	Total stream, lb/hr	4,905,800	4,980,600	4,980,600	5,195,300	5,181,200
2	sft^3/min (60°F)	1,056,000	1,070,200	1,070,200	1,143,800	1,143,900
3	Temperature, °F	300	298	311	130	134
4	Pressure, psia (in. WG)			(19)	(13)	(4)
5	gpm					
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	11	12	13	14	15
	Description	Gas to stack	Steam to reheater	Makeup water to chloride scrubber	Pond water to recirculation tank	*Mist eliminator wash water to SO_2 absorber
1	Total stream, lb/hr	5,181,200	79,700	225,400	55,400	100,000
2	sft^3/min (60°F)	1,145,800				
3	Temperature, °F	175	470	80	80	80
4	Pressure, psia (in. WG)		515			
5	gpm			450	110	200
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	16	17	18	19	20
	Description	Absorber effluent to filter	*Sluicing water to filter	Filtered effluent to absorber product tank	*Filter sluice to effluent sump	*Filter aid to precoat tank
1	Total stream, lb/hr	390,400	150,100	390,300	150,700	(100 lb)
2	sft^3/min (60°F)					
3	Temperature, °F	134	80	134	80	
4	Pressure, psia (in. WG)					
5	gpm	600	300	600	300	
6	Specific gravity	1.3		1.3		
7	pH					
8	Undissolved solids, %					
9						
10						

*Intermittent streams, 24 hour average rates for streams 15 and 17 are 1.5 and 6 gpm respectively.

(continued)

TABLE 14 (continued)

	Stream No.	21	22	23	24	25
	Description	Chloride scrubber effluent to neutralization tank	Limestone to neutralization tank	Neutralized waste to ash pond	Heated absorber product	Condensate to dissolving tank
1	Total stream, lb/hr	66,100	900	66,900	390,300	231,800
2	sft^3/min (60°F)					
3	Temperature, °F	130			145	143
4	Pressure, psia (in. WG)					
5	gpm	130		130	600	460
6	Specific gravity	1.01		1.01	1.3	
7	pH	1				
8	Undissolved solids, %					
9						
10						

	Stream No.	26	27	28	29	30
	Description	Heated absorber product to evaporator preheaters	Heated absorber product to sulfate crystallizer	Sulfate crystallizer liquor to centrate tank	Sulfate crystallizer condensate to clean condensate tank	Crystallizer bottoms to centrifuge
1	Total stream, lb/hr	370,000	66,400	41,500	20,000	6,600
2	sft^3/min (60°F)					
3	Temperature, °F	152	145	205	161	205
4	Pressure, psia (in. WG)					
5	gpm	570	102	60	40	8
6	Specific gravity	1.3	1.3	1.34		1.6
7	pH					
8	Undissolved solids, %					30
9						
10						

	Stream No.	31	32	33	34	35
	Description	Centrifuge cake to dryer	Dryer product o storage	Steam to dryer	Sulfate crystallizer liquor to regeneration area	Steam to sulfate crystallizer
1	Total stream, lb/hr	2,000	2,300	1,400	46,100	20,000
2	sft^3/min (60°F)					
3	Temperature, °F	205	270	470	205	250
4	Pressure, psia (in. WG)			515		30
5	gpm				70	
6	Specific gravity				1.34	
7	pH					
8	Undissolved solids, %	90				
9						
10						

	Stream No.	36	37	38	39	40
	Description	Sulfate crystallizer vapor to regeneration area	Feed to second effect evaporator	Second effect evaporator condensate to stripper	First effect vapor to primary condenser	Second effect evaporator liquor to dissolving tank
1	Total stream, lb/hr	18,300	159,100	93,700	53,800	61,800
2	sft^3/min (60°F)	6,300			16,100	
3	Temperature, °F	205	170	187	187	170
4	Pressure, psia (in. WG)	10			4.5	
5	gpm		240	190		70
6	Specific gravity		1.3			1.66
7	pH					
8	Undissolved solids, %					50
9						
10						

(continued)

TABLE 14 (continued)

	Stream No.	41	42	43	44	45
	Description	Second effect vapor to primary condenser	Combined vapor to primary condenser	Cooling water to condensers	Steam to stripper	SO_2-rich gas to compressor
1	Total stream, lb/hr	97,400	151,200	4,783,700	9,000	22,100
2	sft^3/min (60°F)	32,100	48,200			2,900
3	Temperature, °F	170	176	80	250	110
4	Pressure, psia (in. WG)	4.5	4.5		30	3.5
5	gpm			9,560		
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	46	47	48	49	50
	Description	Feed to first effect evaporator	First effect vapor to second effect heater	Steam to first effect heater	First effect evaporator liquor to decanter	Decanter underflow to dissolving tank
1	Total stream, lb/hr	210,900	129,100	127,200	81,900	80,600
2	sft^3/min (60°F)		42,500			
3	Temperature, °F	205	205	250	205	205
4	Pressure, psia (in. WG)		10	30		
5	gpm	320			100	100
6	Specific gravity	1.3			1.66	1.66
7	pH					
8	Undissolved solids, %				50	51
9						
10						

	Stream No.	51	52	53	54	55
	Description	Condensate to second effect feed preheater	Condensate to first effect feed preheater	Condensate from second effect feed preheater	Condensate from first effect feed preheater	Stripper bottoms to absorber product heater
1	Total stream, lb/hr	25,900	101,300	25,900	101,300	231,800
2	sft^3/min (60°F)					
3	Temperature, °F	250	250	166	167	157
4	Pressure, psia (in. WG)					
5	gpm	50	200	50	200	460
6	Specific gravity					
7	pH					
8	Undissolved solids, %					
9						
10						

	Stream No.	56	57	58	59	60
	Description	Condensate to soda ash storage tank	Makeup soda ash to storage tank	Soda ash solution to dissolving tank	Scrubbing solution to SO_2 absorber	Dissolving tank vent to plenum
1	Total stream, lb/hr	3,800	1,800	5,600	375,200	800
2	sft^3/min (60°F)					110
3	Temperature, °F	143		110	153	153
4	Pressure, psia (in. WG)					
5	gpm	8		9	600	
6	Specific gravity			1.33	1.26	
7	pH					
8	Undissolved solids, %					
9						
10						

(continued)

TABLE 14 (continued)

	Stream No.	61	62	63	64	65
	Description	Dryer offgas to plenum	Thiosulfate purge to dryer	Acid plant tailgas to plenum	Combined gases to plenum	SO_2-rich gas to end plant
1	Total stream, lb/hr	1,000	1,300	73,000	74,800	22,100
2	sft^3/min (60°F)	320		16,000	16,400	2,930
3	Temperature, °F	270	205	170	170	382
4	Pressure, psia (in. WG)					15
5	gpm		2			
6	Specific gravity		1.26			
7	pH					
8	Undissolved solids, %					
9						
10						

1						
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design drawings shown in Figures 6-8 apply to all three processes. The flow diagram and the base-case material balance for the sulfuric acid unit are shown in Figure 9 and Table 15 respectively.

The Wellman-Lord/sulfuric acid process is divided into nine operating areas: materials handling, gas handling, chloride removal, SO_2 absorption, stack gas reheat, sulfate crystallization, regeneration, sulfuric acid production, and acid storage and shipment. Table 16 contains a description of the equipment items in each area and the purchase cost of the equipment. The costs in Table 16 are the purchase cost only and do not include cost of erection.

Expenditures for all flue gas ductwork are accounted for in the gas handling area. The acid production area investment is a battery-limits quotation by a sulfuric acid unit vendor. In addition to the previously described direct investment components, the acid unit estimate shown in Table 16 includes all indirect investment costs incurred by the vendor. This indirect cost is 45% of the battery-limits quotation.

Materials Handling Area

Dry soda ash containing 99.8% Na_2CO_3 is unloaded from pneumatic equipped transporters and stored as a wet slurry in a tank with a 30-day capacity. The storage system is the same as the one described for the ACP. Minor equipment differences are the result of different process requirements and vendor design differences. As this solution is removed to supply the system makeup requirements, process condensate at about 140°F is sparged into the tank bottom to dissolve $Na_2CO_3 \cdot H_2O$ and replenish the Na_2CO_3 solution.

Gas Handling Area

A common plenum is situated downstream from the ESP units and the power plant ID fans to distribute gas to the four trains of the absorption system. A booster forced-draft (FD) fan in each train between the plenum and the absorber compensates for the pressure drop through the FGD system. This study assumes the flue gas enters the plenum at 300°F. Mixing 300°F flue gas with 170°F recycle gas from the sulfuric acid unit produces a mixture of gases at 298°F. A temperature rise to 311°F is used, assuming that the gas contains the adiabatic heat of compression and all frictional heat generated. After passing through the FGD system and reheater the flue gas of each train is ducted to the stack plenum. All equipment downstream from the power plant ID fans and upstream from the stack plenum is included in the FGD costs.

Chloride Neutralization Area

The flue gas is first cooled and humidified and approximately 70% of the chloride is removed in a low-energy venturi scrubber upstream from each SO_2 scrubber. The venturi scrubbers use recycle pond liquor. Further chloride removal is accomplished in a spray chamber equipped with three banks of nozzles spraying perpendicularly to the gas flow.

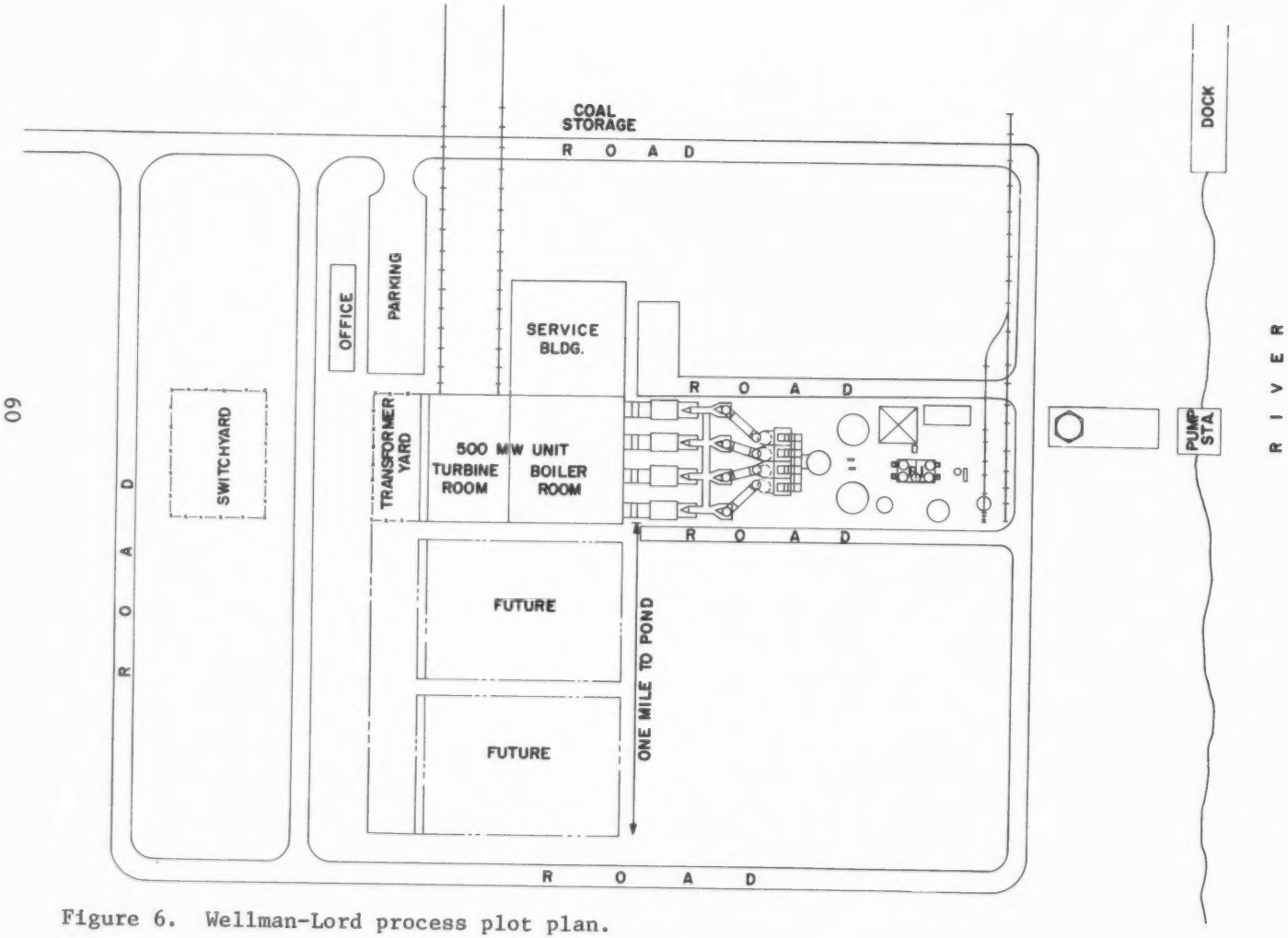

Figure 6. Wellman-Lord process plot plan.

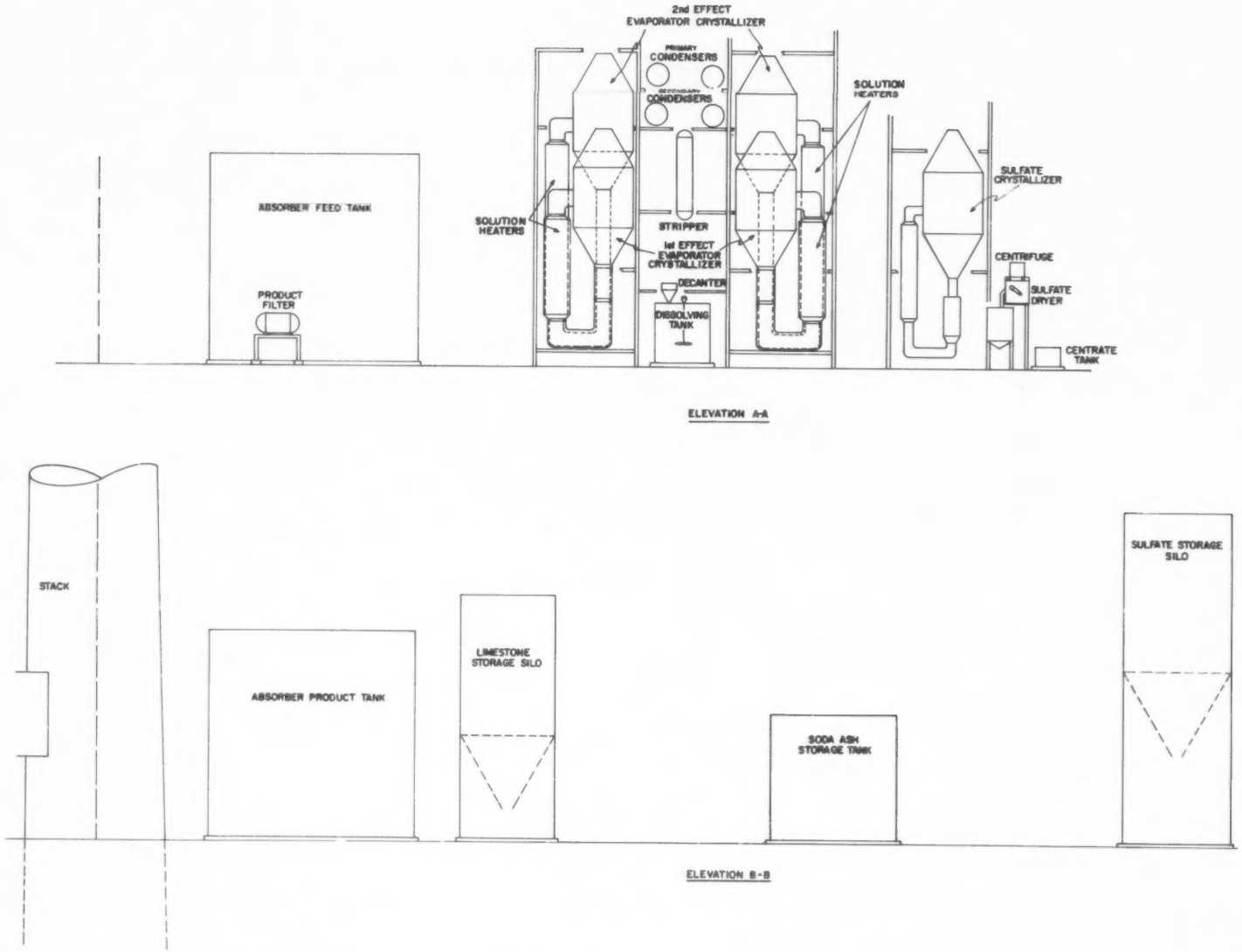

Figure 7. Wellman-Lord process regeneration area elevation drawing.

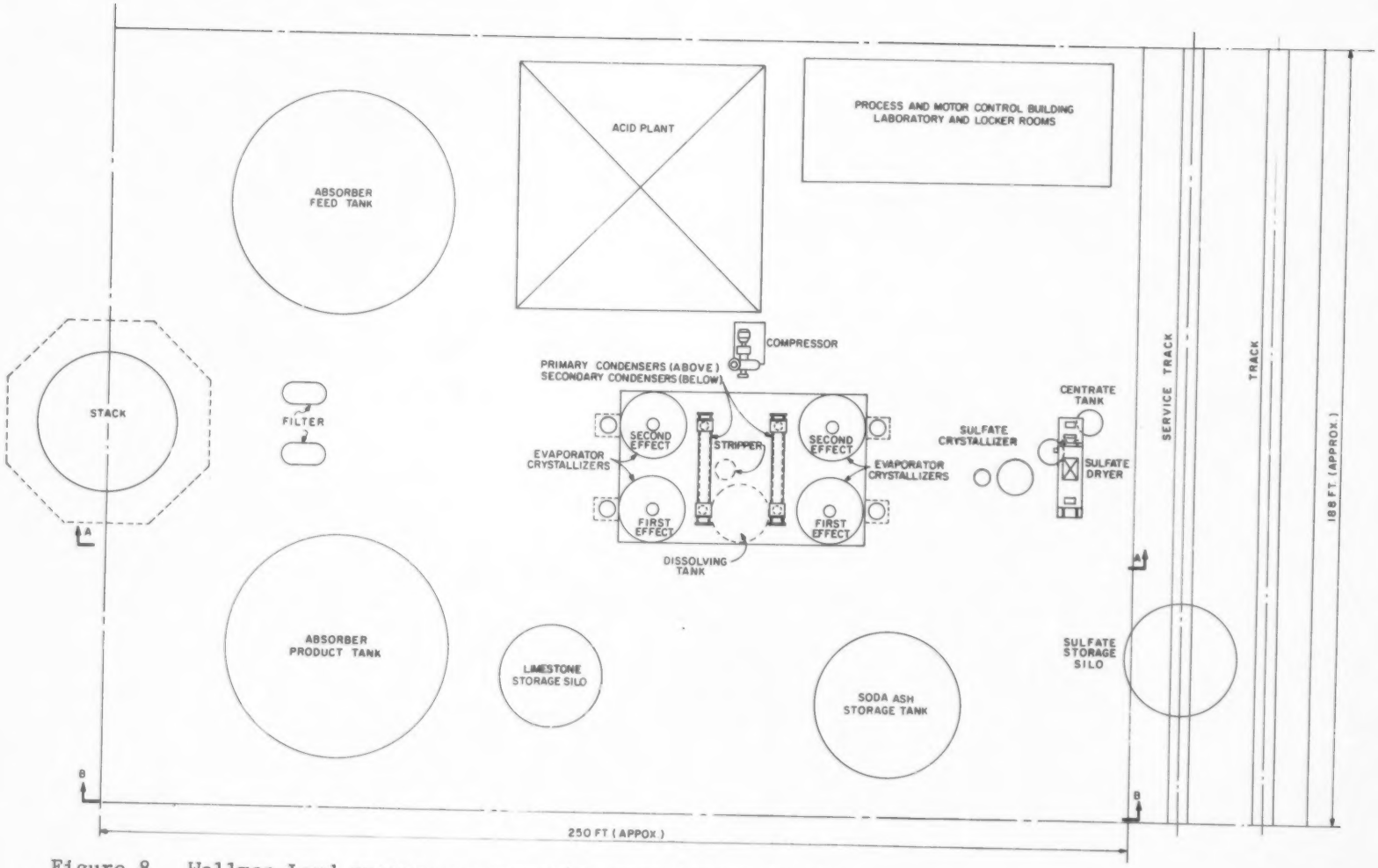

Figure 8. Wellman-Lord process regeneration area layout drawing.

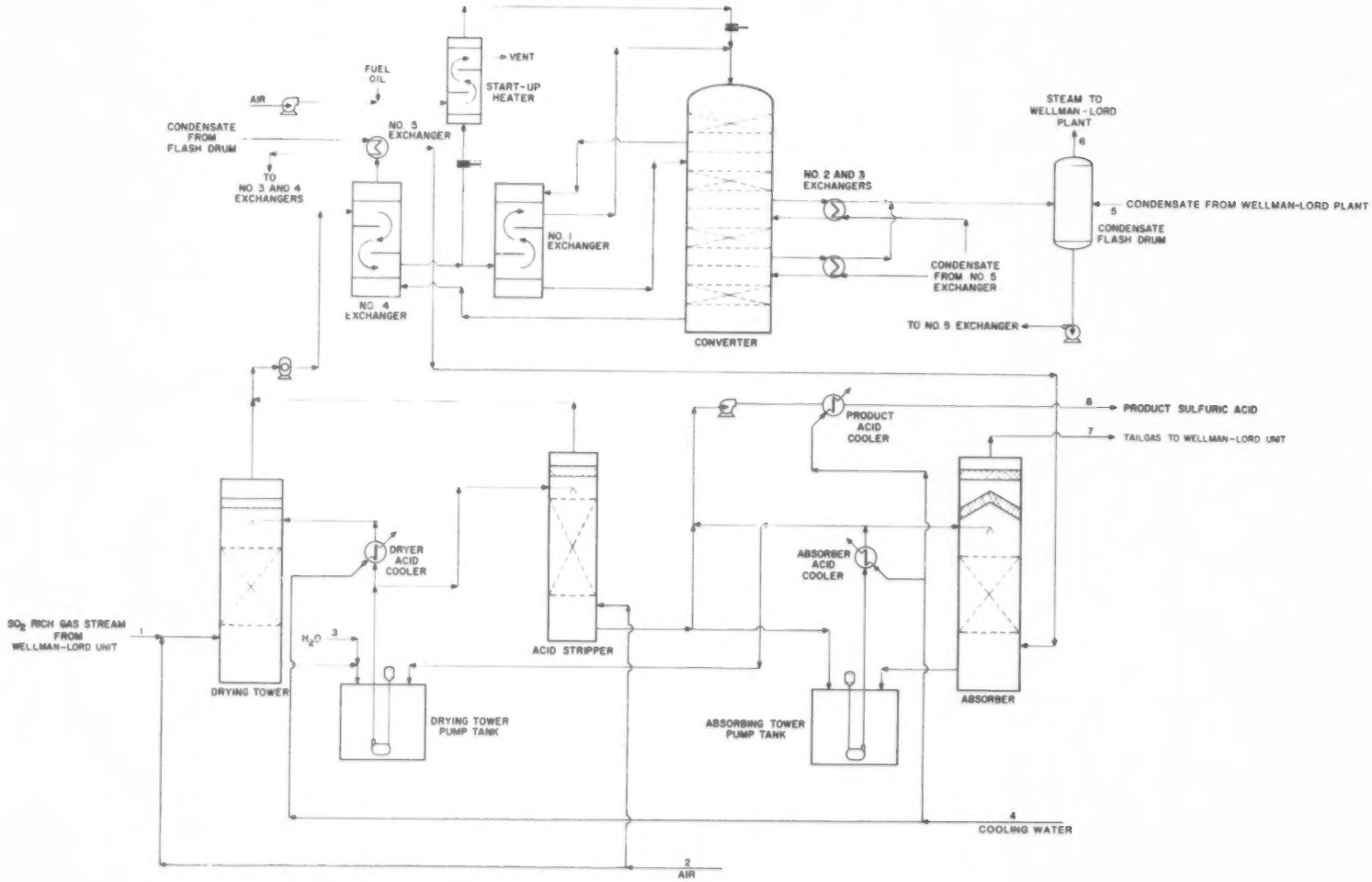

Figure 9. Sulfuric acid unit flow diagram.

TABLE 1[illegible]. SULFURIC ACID UNIT

BASE CASE MATERIAL BALANCE

	Stream No.	1	2	3	4	5
	Description	Gas from Wellman-Lord plant	Process air	Process water	Cooling water	Condensate from Wellman-Lord plant
1	Total stream, lb/hr	22,100	77,300	2,840	1,050,800	6,800
2						
3						
4	ft^3/min (60°F)	2,930	16,900			
5	Temperature, °F	382	80	80	80	165
6	Pressure, psia	15				
7	Gpm			6	2,100	14
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	6	7	8		
	Description	Steam to Wellman-Lord plant	Tail gas to SO_2 absorber	98% H_2SO_4		
1	Total stream, lb/hr	6,800	73,000	29,200		
2						
3						
4	ft^3/min (60°F)		16,000			
5	Temperature, °F	250	170	110		
6	Pressure, psia	30				
7	Gpm			32		
8	Specific gravity			1.82		
9	pH					
10	Undissolved solids, %					

1						
2						
3						
4						
5						
6						
7						
8						
9						
10						

1						
2						
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4						
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TABLE 16. WELLMAN-LORD/SULFURIC ACID PROCESS

BASE-CASE EQUIPMENT LIST

Area 1--Material Handling

Item	No.	Description	Total material cost, 1979 $
1. Car shaker	1	Top mounting with crane, 20 hp shaker, 7-1/2 hp crane	19,900
2. Tank, soda ash storage	1	33 ft dia x 32-1/2 ft high, 207,950 gal, w/cover, carbon steel, insulated, 3 spargers in bottom (30-day capacity)	38,400
3. Pump, soda ash feed	2	Centrifugal, 9 gpm, 60 ft head, 1/2 hp, carbon steel (1 operating, 1 spare)	3,300
4. Dust collecting system	1	Bag filter, polypropylene bag, 4,000 aft^3/min, automatic shaker system	12,200
5. Conveyor, limestone	1	Pneumatic, positive pressure, conveying system, 41 tons/hr, 75 hp	102,900
6. Silo, limestone storage	1	19 ft dia x 29 ft straight side, 8,200 ft^3, 60° slope, 3/8 in. carbon steel hopper (30-day capacity)	13,000
7. Bin, limestone feed	1	5-1/2 ft dia x 8-1/2 ft straight side height, w/cover, 30° cone hopper, carbon steel (8-hr capacity)	1,500
Subtotal			191,200

Area 2--Gas Handling

Item	No.	Description	Total material cost, 1979 $
1. Fans	4	Forced draft, 390,000 aft^3/min, 19.7 in. static head, 1,750 hp fluid drive, double width, double inlet	864,000
Subtotal			864,000

(continued)

TABLE 16 (continued)

Area 3--Chloride Neutralization

Item	No.	Description	Total material cost, 1979 $
1. Chloride scrubber	4	Venturi-spray chamber combination, venturi: 13 ft dia x 25 ft overall height, variable throat, carbon steel, elastomer and tile lined, Hastelloy G throat Spray chamber: 24 ft x 20 ft x 11 ft high, carbon steel, elastomer and tile lined, Hastelloy G nozzles with stellite tips; Hastelloy G mist eliminator	1,834,200
2. Tank, recirculation	4	20 ft dia x 6 ft high, 14,100 gal, w/cover, four 20 in. baffles, agitator supports, carbon steel, neoprene lined, insulated (10-min capacity)	29,400
3. Agitator, recirculation tank	4	80 in. dia, 1-1/2 hp, neoprene coated	15,200
4. Pump, venturi recirculation	8	Centrifugal, 3,140 gpm, 60 ft head, 100 hp, carbon steel, neoprene lined (4 operating, 4 spares)	118,200
5. Pump, spray chamber recirculation	8	Centrifugal, 3,140 gpm, 150 ft head, 250 hp, carbon steel, neoprene lined (4 operating, 4 spares)	212,500
6. Tank, neutralization	1	11-1/2 ft dia x 6 ft high, 4,660 gal, w/cover, four 11-1/2 in. baffles, agitator supports, carbon steel, neoprene lined, insulated (30-min capacity)	2,700
7. Agitator, neutralization tank	1	46 in. dia, 1 hp, neoprene coated	2,700

(continued)

TABLE 16 (continued)

Item	No.	Description	Total material cost, 1979 $
8. Pump, pond feed	2	Centrifugal, 130 gpm, 150 ft head, 15 hp, carbon steel, neoprene lined (1 operating, 1 spare)	11,200
9. Pump, pond water return	2	Centrifugal, 300 gpm, 150 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	16,200
10. Feeder, limestone feed bin discharge	1	Weigh, screw, 6 in. dia x 10 ft long, 1 hp, 900 lb/hr	5,300
11. Pump, raw water	2	Centrifugal, 650 gpm, 150 ft head, 60 hp, carbon steel (1 operating, 1 spare)	18,200
12. Pump, chloride scrubber water booster	2	Centrifugal, 450 gpm, 150 ft head, 40 hp, carbon steel (1 operating, 1 spare)	17,000
Subtotal			2,282,800

Area 4--SO_2 Absorption

Item	No.	Description	Total material cost, 1979 $
1. SO_2 absorber	4	Valve tray, 24 ft x 24 ft x 50 ft high, concrete, tile lined, insulated, 3-316 stainlesss steel valve trays, 2-316 stainless steel chimney trays, 1-316 stainless steel mist eliminator	1,414,400
2. Pump, SO_2 absorber recirculation	16	Centrifugal, 550 gpm, 20 ft head, 10 hp, carbon steel, neoprene lined (12 operating, 4 spares)	60,700
3. Pump, absorber effluent	8	Centrifugal, 150 gpm, 200 ft head, 25 hp, carbon steel, neoprene lined (4 operating, 4 spares)	65,600

(continued)

TABLE 16 (continued)

	Item	No.	Description	Total material cost, 1979 $
4.	Filter, absorber product	2	Pressure leaf, 60 in. dia x 11 ft long, 800 ft^2, 316 stainless steel, insulated	202,800
5.	Sump, effluent	1	8 ft x 8 ft x 8 ft deep, concrete, tile lined, grating covered	7,000
6.	Agitator, effluent sump	1	32 in. dia, 2 hp, neoprene coated	6,200
7.	Pump, effluent	2	Centrifugal, submerged, 100 gpm, 60 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	5,300
8.	Tank, absorber product	1	54-1/2 ft dia x 54-1/2 ft high, 951,100 gal, w/cover, concrete, tile lined, insulated (24-hr capacity)	157,000
9.	Pump, absorber product tank	2	Centrifugal, 600 gpm, 100 ft head, 50 hp, carbon steel, neoprene lined (1 operating, 1 spare)	11,600
10.	Heater, absorber product	1	Plate and frame type heat exchanger, 350 ft^2, 316 stainless steel, insulated	8,300
11.	Soot blowers	20	Air, retractable	130,000
	Subtotal			2,068,900

Area 5--Reheat

	Item	No.	Description	Total material cost, 1979 $
1.	Reheaters	4	Steam, tube type, 3,170 ft^2, one-half tubes made of Inconel 625, and one-half made of Cor-Ten	787,200
2.	Soot blowers	20	Air, retractable	130,000
	Subtotal			917,200

(continued)

TABLE 16 (continued)

Area 6--Sulfate Crystallization

	Item	No.	Description	Total material cost, 1979 $
1.	Preheater, crystallizer feed	1	Plate and frame type, 80 ft^2, 316 stainless steel, insulated	3,600
2.	Crystallizer, sulfate	1	9 ft dia x 12 ft straight side, 316 stainless steel, insulated	651,800
	Heater	1	Shell and tube type, 3,000 ft^2, 316 stainless steel tubes and heads, carbon steel shell, insulated	
	Recirculation pump	1	Axial, 18,000 gpm, 15 ft head, 250 hp, 316 stainless steel	
3.	Receiver, condensate	1	2 ft dia x 4 ft high, 90 gal, w/cover, carbon steel, insulated	300
4.	Pump, condensate	2	Centrifugal, 40 gpm, 60 ft head, 2 hp, carbon steel (1 operating, 1 spare)	3,400
5.	Pump, centrifuge feed	2	Centrifugal, 8 gpm, 60 ft head, 3/4 hp, 316 stainless steel (1 operating, 1 spare)	4,800
6.	Centrifuge	1	Solid bowl, continuous, 30 hp, 316 stainless steel	80,800
7.	Tank, centrate	1	5 ft dia x 5-1/2 ft high, 810 gal, w/cover, four 5-in. baffles, agitator supports, 316 stainless steel, insulated (10-min capacity)	8,000
8.	Agitator, centrate tank	1	2 turbines, 20 in. dia, 1-1/2 hp, 316 stainless steel	3,800
9.	Pump, centrate tank	2	Centrifugal, 70 gpm, 100 ft head, 7-1/2 hp, 316 stainless steel (1 operating, 1 spare)	7,600
10.	Dryer	1	Mechanically agitated, twin screw, 316 stainless steel, insulated	262,200

(continued)

TABLE 16 (continued)

Item	No.	Description	Total material cost, 1979 $
11. Dust collecting system	1	Bag filter, polypropylene bag, 450 aft^3/min, automatic shaker system	9,000
12. Hopper, sulfate surge	1	6-1/2 ft dia x 9 ft high, 280 ft^3, w/cover, carbon steel	4,500
13. Conveyor, sulfate	1	Pneumatic, positive pressure, conveying system, 1 ton/hr, 10 hp	36,000
14. Silo, sulfate storage	1	28 ft dia x 41-1/2 ft straight side height, 25,550 ft^3, 60° slope, 3/8 in. carbon steel hopper (30-day capacity)	34,900
15. Feeder, sulfate silo discharge	1	Vibrating pan, 2 hp, 100 tons/hr	3,800
Subtotal			1,114,500

Area 7--Regeneration

Item	No.	Description	Total material cost, 1979 $
1. Preheater, first effect evaporator feed	1	Plate and frame type, 300 ft^2 316 stainless steel, insulated	6,800
2. Preheater, second effect evaporator feed	1	Plate and frame, 90 ft^2, 316 stainless steel, insulated	3,700
3. Evaporator system, double effect unit including:	2		2,616,300
Evaporator, first effect	2	16 ft dia x 16 ft straight side height, 316 stainless steel, insulated	
Heater, first effect	2	Shell and tube type, 8,900 ft^2, 316 stainless steel tubes and heads, carbon steel shell, insulated	

(continued)

TABLE 16 (continued)

	Item	No.	Description	Total material cost, 1979 $
	Pumps, first effect recirculation	2	Axial, 62,000 gpm, 15 ft head, 900 hp, 316 stainless steel (2 operating, 0 spare)	
	Evaporator, second effect	2	16 ft dia x 16 ft straight side height, 316 stainless steel, insulated	
	Heater, second effect	2	Shell and tube type, 13,300 ft^2, 316 stainless steel tubes, heads, and shell, insulated	
	Pumps, second effect recirculation	2	Axial, 45,000 gpm, 15 ft head, 600 hp, 316 stainless steel (2 operating, 0 spare)	
4.	Receiver, first effect condensate	2	3-1/2 ft dia x 4 ft high, 290 gal, w/cover, carbon steel, insulated	1,100
5.	Receiver, second effect condensate	2	3 ft dia x 4 ft high, 210 gal, w/cover, 316 stainless steel, insulated	7,000
6.	Pump, first effect condensate	4	Centrifugal, 130 gpm, 60 ft head, 5 hp, carbon steel (2 operating, 2 spares)	10,600
7.	Pump, second effect condensate	4	Centrifugal, 90 gpm, 60 ft head, 5 hp, 316 stainless steel (2 operating, 2 spares)	15,600
8.	Tank, dissolving	1	14-1/2 ft dia x 15-1/2 ft high, 19,150 gal, w/cover, four 14-1/2 in. baffles, agitator supports, carbon steel, neoprene lined, insulated (30-min capacity)	14,200
9.	Agitator, dissolving tank	1	2 turbines, 58 in. dia, 7-1/2 hp, neoprene coated	12,000
10.	Pump, dissolving tank	2	Centrifugal, 580 gpm, 100 ft head, 40 hp, carbon steel, neoprene lined (1 operating, 1 spare)	10,500

(continued)

TABLE 16 (continued)

Item	No.	Description	Total material cost, 1979 $
11. Separator, mother liquor	2	4 ft dia x 2 ft straight side, 60° slope, 316 stainless steel, insulated	11,500
12. Pump, mother liquor	2	Centrifugal, 2 gpm, 60 ft head, 1/2 hp, 316 stainless steel, (1 operating, 1 spare)	3,300
13. Tank, absorber feed	1	54-1/2 ft dia x 54-1/2 ft high, 951,130 gal, w/cover, concrete, tile lined, insulated (24-hr capacity)	157,000
14. Pump, absorber feed tank	2	Centrifugal, 580 gpm, 100 ft head, 40 hp, carbon steel, neoprene lined (1 operating, 1 spare)	10,500
15. Stripper	1	4-1/2 ft dia x 20 ft overall height, packed tower, 316 stainless steel, insulated	51,500
16. Pump, stripper	2	Centrifugal, 460 gpm, 100 ft head, 25 hp, carbon steel, neoprene lined (1 operating, 1 spare)	9,100
17. Condenser, primary	2	Shell and tube type, 5,100 ft^2, 316 stainless steel tubes, heads, and shell	130,000
18. Condenser, secondary	2	Shell and tube type, 4,100 ft^2, 316 stainless steel tubes, heads, and shell	111,200
19. Pump, cooling water	4	Centrifugal, 4,780 gpm, 150 ft head, 400 hp, carbon steel, neoprene lined (2 operating, 2 spares)	130,600
20. Blower, product gas	1	Centrifugal, single stage, 2,930 sft^3/min, 500 hp, 316 stainless steel	187,000
21. Tank, central condensate	1	8-1/2 ft dia x 8-1/2 ft high, 3,610 gal, w/cover, carbon steel, insulated (10-min capacity)	2,500

(continued)

TABLE 16 (continued)

	Item	No.	Description	Total material cost, 1979 $
22.	Pump, condensate return	2	Centrifugal, 310 gpm, 150 ft head, 25 hp, carbon steel (1 operating, 1 spare)	16,200
	Subtotal			3,518,200

Area 8--98% Sulfuric Acid Production

	Item	No.	Description	Total material cost, 1979 $
1.	Complete H_2SO_4 unit	1	Complete 98% sulfuric acid system (battery limits cost)	5,600,000
	Subtotal			5,600,000

Area 9--Acid Storage and Shipping

	Item	No.	Description	Total material cost, 1979 $
1.	Tank, acid storage	2	49 ft dia x 50 ft high, 705,400 gal, w/cover, carbon steel, insulated (15-day capacity each)	185,800
2.	Pump, acid storage tank discharge	2	Centrifugal, 400 gpm, 100 ft head, 40 hp, carbon steel, insulated (1 operating, 1 spare)	10,500
	Subtotal			196,300

Recycle liquor is sprayed from the first two banks and fresh make up water from the third bank. From the chloride scrubber recycle tank a bleedstream of chloride-rich liquor overflows to a neutralizing tank to which agricultural limestone is added. The neutralized waste stream is pumped to the existing power plant ash pond. It is assumed that 85% of the water in this waste stream is returned to the chloride recycle tank. A chevron mist eliminator, placed between the spray chamber and the SO_2 absorber, prevents the carryover of chlorides to the absorber by removing most of the entrained water.

SO_2 Absorption and Reheat Areas

The Wellman-Lord SO_2 absorbers consist of four self-supporting, tile-lined, reinforced-concrete vessels that share common walls and rest on the ground. According to the manufacturer, the initial cost is lower than that for either a neoprene-lined carbon steel or 316 stainless steel vessel because of the common wall arrangement and the elimination of a superstructure to support the vessels. The vessels can be designed to support internal and external equipment. They are also claimed to require less maintenance and to be more reliable than alloy steels or elastomer-lined steels.

The SO_2 absorbers are valve tray towers with three valve trays, each separated by a chimney tray, and a chevron mist eliminator. The chimney trays provide adequate gas-liquid contact during periods when rapid liquid-rate changes are made in response to changing flue gas rates. The Na_2SO_3-rich scrubbing solution is individually recirculated around each valve tray to provide a higher degree of countercurrent contact between the flue gas and the liquor. Fresh solution is introduced above the top SO_2 absorber valve tray and successively overflows from each valve tray into the next until it reaches the bottom of the tower. Most of the absorbed SO_2 reacts with Na_2SO_3 and H_2O to produce $NaHSO_3$. In addition, a relatively small amount of Na_2SO_4 is formed by reaction of Na_2SO_3 with SO_3 and O_2. The spent absorber effluent is collected in the bottom section of the tower, filtered in a precoat-type pressure leaf filter to remove residual fly ash, and pumped to a 24-hour-capacity surge tank. Two filters, on line alternately, serve all four absorbers. The filters are periodically sluiced with pond water, which is dumped to a sump and used in the chloride scrubber. From the surge tank about 17% of the effluent is pumped to the sulfate crystallization area and the remainder is pumped to the regeneration area.

The flue gas enters the absorber at 130°F and the cleaned, saturated gas leaves the absorber at about 134°F, a temperature higher than the typical FGD absorber exit temperature of 127°F, because the regenerated scrubbing solution enters at 150°F and because the highly concentrated sodium-salt scrubbing liquor solution has a boiling point elevation of 5°F, resulting in less evaporative cooling. It is also assumed that heat loss to the environment through the absorber walls is negligible because the absorber is well insulated. The cleaned gas is first passed through a chevron mist eliminator to reduce the entrained moisture to 0.1% and is then heated to 175°F in an indirect steam reheater before entering the stack plenum.

Sulfate Crystallization Area

About 17% of the scrubber effluent is processed to remove Na_2SO_4 by selective crystallization in a single steam-heated, forced-circulation, single-effect evaporator operating at 10 psia and 205°F. The bottoms, consisting of a slurry enriched in Na_2SO_4, are centrifuged to produce a 90% solids cake. The centrifuge cake is dried in a steam-heated, mechanically agitated dryer to produce a byproduct that is about two-thirds Na_2SO_4 and one-third Na_2SO_3. The byproduct is conveyed pneumatically to a 30-day-capacity silo for storage until sale. The centrate is combined with clear evaporator overflow and the resulting $NaHSO_3$-enriched solution is pumped to the regeneration area.

Regeneration Area

The regeneration area consists of two trains of double-effect, forced-circulation evaporators, a two-train condenser system, a stripper, a compressor, and a dissolving tank. The first-effect evaporators operate at 10 psia and 205°F. The second-effect evaporators operate at 4.5 psia and 170°F. The evaporator feed stream is scrubber effluent combined with liquid from the sulfate removal section. The feed is divided into two streams and heated from 152°F to the evaporator operating temperatures. One stream (60% of the total) is pumped to the first-effect evaporators and the other stream (40% of the total) is pumped to the second-effect evaporators. In the evaporators, the feed stream is heated at a controlled rate to produce an overhead vapor of SO_2 and H_2O and to produce a bottoms slurry enriched in Na_2SO_3 crystals. The heating medium for the first-effect evaporators is steam. The first-effect vapor and the sulfate crystallizer vapor are combined and used as the heating medium in the second-effect evaporators.

The bottoms from the second-effect evaporators flow to a dissolving tank. Highly soluble $Na_2S_2O_3$ is formed in the first-effect evaporators because of their higher operating temperature. To control $Na_2S_2O_3$ concentration, first-effect evaporator bottoms are routed through a decanter. A small liquid purge stream overflows to the sulfate dryer and the underflow flows to the dissolving tank.

About 60% of the vapor heating the second-effect evaporators condenses and is pumped to a steam-stripper where SO_2 is removed. The stripper also treats condensate from the condenser system. Saturated 250°F steam supplied to the bottom of the stripper countercurrently contacts the condensate in a packed bed to remove SO_2. The stripper operates at about 4 psia.

The uncondensed first-effect vapor from the second-effect heaters is combined with second-effect evaporator overhead vapor and the combined gas stream, containing about 96 mole % H_2O, flows through the condenser system. Each of the two trains in the condenser system contains two water-cooled condensers arranged in series. In the primary condensers about two-thirds of the water vapor is condensed. The remaining gas is combined with the overhead vapor from the stripper and the mixture flows

to the secondary condensers. In the secondary condensers, the gas is cooled to about 110°F and dried by H_2O condensation to about 36 mole % H_2O. The cooled, dried gas at about 3.5 psia is compressed to atmospheric pressure by a single-stage dry centrifugal compressor and routed to the SO_2 processing unit.

Condensate from the primary and secondary condensers, along with condensate from the second-effect evaporator heaters, is treated in the stripper to remove dissolved SO_2. The stripped condensate is cooled by heat exchange with absorber effluent and mixed with evaporator bottoms in the dissolving tank to dissolve the Na_2SO_3 crystals. Na_2CO_3 solution is added to the mixture to replenish sodium lost from the system in the dryer product. The resulting liquor is pumped to a 24-hour-capacity surge tank for storage until it is needed in the absorbers.

Sulfuric Acid Production Area

The 64 mole % SO_2 stream from the Wellman-Lord process is converted to H_2SO_4 in a conventional 98% efficient, single-contact, single-absorption acid unit. The SO_2-rich gas stream is drawn into a packed drying tower along with sufficient air to produce a 10 mole % SO_2 concentration at the converter inlet. In the drying tower, the gas is passed counter-currently to a stream of 93% H_2SO_4. The acid enters the tower at 110°F, is heated to 150°F by dilution with absorbed water, and is recirculated through a cooler to the top of the tower. Since there is insufficient water in the SO_2 - air stream for the reaction between SO_3 and H_2O, additional water is added to drying tower recycle stream. To maintain a 93% H_2SO_4 concentration in the drying tower recycle stream, some of the byproduct 98% acid must be added to the stream.

The drying tower recycle stream also contains dissolved SO_2. To remove the SO_2, some of the 93% acid produced in the drying tower system is withdrawn and routed to a packed stripper. The dissolved SO_2 is stripped by countercurrently contacting the acid with air. The SO_2 and air mixture is routed to the main gas stream leaving the drying tower. The stripped acid is added to the SO_3 absorption tower to maintain the proper acid concentration. Entrainment separators in the stripper and dryer prevent carryover of acid mist in the gas streams. The combined stripper and dryer gas is passed through two heat exchangers in series where it is preheated to 820°F with hot gases from the first and last beds of the SO_2/SO_3 converter. After preheating, the gas is routed through a four-bed catalytic converter where 98% conversion of SO_2 to SO_3 is achieved. The exit conditions from each bed are: (1) 1150°F and 63% conversion, (2) 965°F and 90% conversion, (3) 855°F and 97% conversion, and (4) 805°F and 98% conversion. The inlet temperature is 820°F for each bed except bed 4 which has an inlet temperature of 800°F. As discussed previously, gas from beds 1 and 4 is used to pre-heat the converter feed stream. The resulting gas, at 505°F, is further cooled to 400°F in heat exchanger 5. The heat recovered in the heat exchangers produces 15 psig steam for use in the Wellman-Lord evaporators.

The 400°F SO_3-rich gas flows to the SO_3 absorption tower where SO_3 is absorbed in a recirculating 98% H_2SO_4 stream. The acid is heated from 170°F to 220°F in cooling the gas and absorbing the SO_3. The acid from the tower flows through a cooler to control temperature. As discussed previously, the water balance for the reaction between SO_3 and H_2O is maintained by adding to the absorber loop some 93% acid from the dryer-stripper loop. The 98% product acid is withdrawn from the absorber loop, cooled to 110°F, and pumped to 30-day-capacity storage tanks.

The gas stream from the absorption tower is at a temperature of 170°F and contains about 2500 ppm SO_2. After passing through an entrainment separator in the absorption tower to remove entrained acid mist, the gas is routed to the flue gas ducts and reenters the Wellman-Lord absorber system.

Storage Capacity

The storage capacity of all tanks and silos is shown in Table 14 as part of the equipment description. Facilities are provided for 30-day storage of all raw materials and products for the process. These include the soda ash storage tank, limestone storage silo, sulfate storage silo, and acid storage tanks. Intermediate in-process storage of limestone in the feed bin is 8 hours. Residence times in the neutralization tank and in the dissolving tank are 30 minutes to allow sufficient time for reactions occurring in those vessels. The absorber product tank and absorber feed tank each have 24 hours capacity. During operation, these two vessels isolate downstream equipment from certain fluctuating conditions. The vessels enable more efficient control and operation of equipment by providing stable conditions in feedstreams. Furthermore, the vessels are useful during outages of the power plant because the equipment downstream of the SO_2 absorption system can continue to operate, thus eliminating some shutdown situations. Likewise, during outages in either the acid unit or the regeneration area, the SO_2 absorbers can continue to operate, thus preventing a power plant shutdown to avoid violation of emission regulations. The chloride scrubber recirculation tank, centrate tank, and central condensate tank exist primarily to provide a volume upstream of pumps. Each of these tanks has a 10-minute capacity and all condensate receivers have 2-minute capacities.

WELLMAN-LORD/RESOX PROCESS

The Resox unit requires a feed gas with a 2:1 to 3:1 molar ratio of H_2O to SO_2 for optimum reducing conditions. This is provided by modifying the Wellman-Lord condensers and compressor to produce an off-gas containing 60 mole % H_2O (the remaining H_2O is supplied by the incinerator gas and anthracite moistures and from anthracite combustion) instead of the 36 mole % H_2O off-gas produced for the sulfuric acid unit. The quantity of SO_2 in the off-gas is also 7% greater than it is for the sulfuric acid case because of the greater quantity returned to the absorbers in the tail gas. Otherwise, the Wellman-Lord process remains the same as for the sulfuric acid case. The flow diagram, plot plan, and elevation and

layout drawings are the same as shown in Figures 5-8. The material balance is also the same as shown in Table 14 except for the flows shown in Table 17.

The Resox unit produces gaseous elemental sulfur in a moving bed reactor by reducing SO_2 with rice-sized anthracite. Anthracite is used because of its low volatile content and nonagglomerating characteristics. For the base-case conditions, the Resox reactor design consists of three separate modules, each containing four reactors. The reactors, however, are not physically separate entities. Each module of four reactors is equipped with four 70° discharge hoppers and four coal inlets, but there are no internal walls to separate the reactors. The modules are constructed of refractory-lined carbon steel. The reactors are designed for a superficial gas velocity of 1 ft/sec and a superficial gas residence time of 4 seconds at full load conditions. Anthracite residence time is about 12 hours.

No mechanical seals are provided at either the coal inlet or discharge. Gas at atmospheric pressure enters the vessel just above the discharge hoppers so that the coal in the hoppers acts as a seal for the reactor bottom. The anthracite feed rate is controlled by the flow rate of spent anthracite withdrawn from the reactor discharge hoppers. There are no mechanical feeders above the reactors; coal flows from the feed bin to the reactors in spider-leg feed tubes, providing a continuous column of anthracite above the reactors. This column of coal seals the vessel at the top. Pressure drop in the Resox unit is overcome by an ID fan downstream from the reactors. There is thus no tendency for the gas to leak through the anthracite seals at the ends of the reactors. The Resox unit flow diagram and material balance are shown in Figure 10 and Table 18. The Resox unit layout drawing is shown in Figure 11. The Resox equipment list (including Wellman-Lord equipment differing from that listed in Table 16) is shown in Table 19.

The Wellman-Lord/Resox process is divided into nine operating areas: materials handling, gas handling, chloride removal, SO_2 absorption, stack gas reheat, sulfate crystallization, regeneration, sulfur production, and sulfur storage. The description of the Wellman-Lord/sulfuric acid process is applicable to the first seven areas.

Sulfur Production Area

Anthracite System--

Rice-sized anthracite coal is received by rail and conveyed to a 30-day stockpile located about 100 feet from the Resox reactors. From the stockpile, the coal is transported to a feed bin above the three reactor modules. Anthracite flows by gravity through the feed bin, feed tubes, and reactors. The flow rate is controlled to provide roughly 2 moles of carbon for each mole of SO_2 by varying the withdrawal rate of spent anthracite from the reactor. Spent anthracite leaves the reactors at $300^{o}F$. The anthracite looses about 50% of its weight in the reactor and is devolatilized but still retains its original size and shape. The spent anthracite is composed mainly of fixed carbon and ash, and possesses

TABLE 17. WELLMAN-LORD PROCESS

BASE-CASE MATERIAL BALANCE

FOR RESOX CASE

(Refer to Table 7)

	Stream No.	11	12	43	63	65
	Description	Gas to stack	Steam to reheater	Cooling water to condensers	Resox plant tail gas to plenum	SO_2-rich gas to Resox plant
1	Total stream, lb/hr	5,144,100	79,200	4,568,000	54,300	29,400
2	Sft^3/min (60°F)	1,135,900			12,200	5,200
3	Temperature (°F)	175	470	80	100	385
4	Pressure (psia)		515			15
5	Gpm			9,130		
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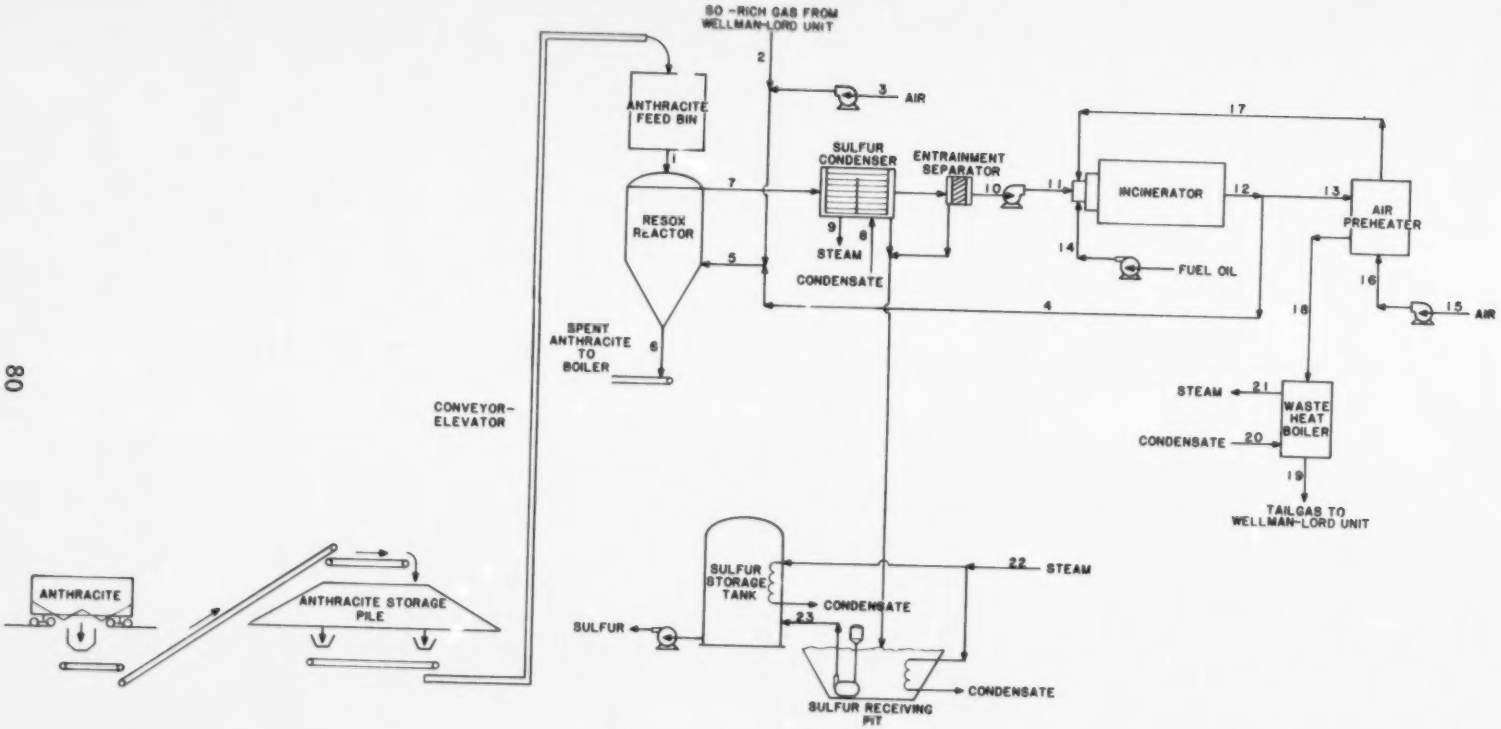

Figure 10. Resox unit flow diagram.

TABLE 18. RESOX UNIT

BASE-CASE MATERIAL BALANCE

Stream No.	1	2	3	4	5
Description	Anthracite to Resox reactor	SO_2-rich gas to feed gas preheater	Air to Resox reactor	Incinerator gas to Resox reactor	Combined gas to Resox reactor
1 Total stream, lb/hr	9,500	29,400	5,200	15,300	49,900
2					
3					
4 Sft^3/min (60°F)		5,200	1,100	3,500	9,800
5 Temperature, °F		385	80	1,500	750
6 Pressure, psia		15			
7 Gpm					
8 Specific gravity					
9 pH					
10 Undissolved solids, %					

Stream No.	6	7	8	9	10
Description	Spent anthracite to boiler	Gas to sulfur condenser	Condensate to sulfur condenser	Steam to Wellman-Lord plant	Gas to fan
1 Total stream, lb/hr	4,900	54,400	11,500	11,500	45,100
2					
3					
4 Sft^3/min (60°F)		11,400			10,500
5 Temperature, °F		650	165	250	295
6 Pressure, psia				30	13.4
7 Gpm			20		
8 Specific gravity					
9 pH					
10 Undissolved solids, %					

Stream No.	11	12	13	14	15
Description	Gas to incinerator	Incinerator gas	Incinerator gas to air preheater	Fuel oil to incinerator	Air to incinerator fan
1 Total stream, lb/hr	45,100	69,600	54,300	800	23,700
2					
3					
4 Sft^3/min (60°F)	10,500	15,700	12,200		5,200
5 Temperature, °F	335	1,500	1,500		80
6 Pressure, psia	15.6				14.7
7 Gpm				2	
8 Specific gravity				0.87	
9 pH					
10 Undissolved solids, %					

Stream No.	16	17	18	19	20
Description	Air to air preheater	Air to incinerator	Tail gas to waste heat boiler	Tail gas to SO_2 absorber	Condensate to waste heat boiler
1 Total stream, lb/hr	23,700	23,700	54,300	54,300	14,200
2					
3					
4 Sft^3/min (60°F)	5,200	5,200	12,200	12,200	
5 Temperature, °F	100	1,100	1,135	300	165
6 Pressure, psia	15.9				
7 Gpm					30
8 Specific gravity					
9 pH					
10 Undissolved solids, %					

(continued)

TABLE 18 (continued)

	Stream No.	21	22	23		
	Description	Steam to Wellman-Lord plant	Steam to receiving pit and sulfur storage tank	Sulfur to storage and shipping		
1	Total stream, lb/hr	14,200	2,400	9,360		
2						
3						
4	Sft^3/min (60°F)					
5	Temperature, °F	250	298	280		
6	Pressure, psia	30	65			
7	Gpm			10		
8	Specific gravity			1.78		
9	pH					
10	Undissolved solids, %					

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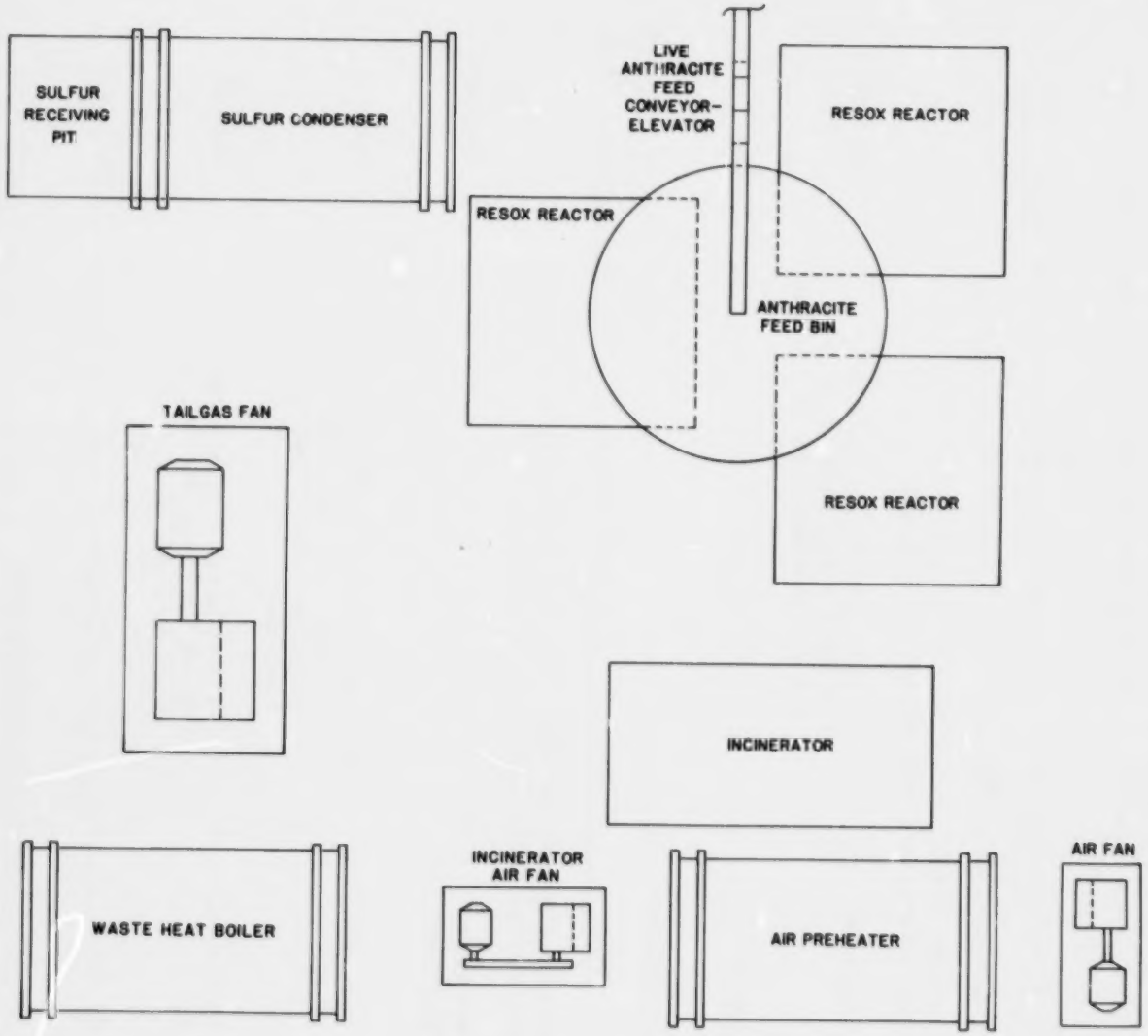

Figure 11. Resox unit layout drawing.

TABLE 19. WELLMAN-LORD/RESOX PROCESS

BASE-CASE EQUIPMENT LIST

Areas 1-4 and Area 6 have the same equipment and costs as those for the Wellman-Lord/sulfuric acid process shown in Table 11.

Area 5--Reheat

Item	No.	Description	Total material cost, 1979 $
All equipment items, descriptions, and costs are identical to Wellman-Lord/sulfuric acid process except for:			
1. Reheaters	4	Steam, tube type, 3,150 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	787,200
Subtotal			917,200

Area 7--Regeneration

Item	No.	Description	Total material cost, 1979 $
All equipment items, descriptions, and costs are identical to Wellman-Lord/sulfuric acid process except for:			
18. Condenser, secondary	2	Shell and tube type, 3,450 ft^2, 316 stainless steel tubes, heads, and shell	98,600
19. Pump, cooling water	4	Centrifugal, 4,360 gpm, 150 ft head, 400 hp, carbon steel, neoprene lined (2 operating, 2 spares)	130,600
20. Blower, product gas	1	Centrifugal, single stage, 5,200 sft^3/min, 900 hp, 316 stainless steel	262,800
Subtotal			3,581,400

Area 8--Sulfur Production (Resox Plant)

Item	No.	Description	Total material cost, 1979 $
1. Car puller	1	25 hp with 5 hp return	50,000

(continued)

TABLE 19 (continued)

Item	No.	Description	Total material cost, 1979 $
2. Hopper, anthracite unloading	1	12 ft x 20 ft x 2 ft bottom, 20 ft deep, 4,800 ft^3, carbon steel	9,300
3. Feeder, anthracite unloading	1	Vibrating pan, 42 in. wide x 60 in. long, 3 hp, 215 tons/hr	4,800
4. Conveyor, anthracite unloading	1	Belt, 30 in. wide x 20 ft long, 1 hp, 215 tons/hr, 300 ft/min	4,600
5. Conveyor, anthracite stocking (incline)	1	Belt, 30 in. wide x 220 ft long, 25 hp, 16° slope, 215 tons/hr, 300 ft/min	49,200
6. Conveyor, anthracite stocking	1	Belt, 30 in. wide x 150 ft long, 7-1/2 hp, 215 tons/hr, 300 ft/min	34,200
7. Tripper	1	5 hp, 30 ft/min	14,800
8. Mobile equipment	1	Scraper tractor, 1-1/2 yd^3 capacity	48,800
9. Hopper, anthracite reclaim	2	2 ft 4 in. x 2 ft 4 in., 4 ft deep, 60° slope, carbon steel	11,200
10. Feeder, live anthracite storage	2	Vibrating pan, 1 hp, 15 tons/hr	7,000
11. Pump, tunnel sump	2	Vertical, 60 gpm, 70 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,400
12. Conveyor, live anthracite feed	1	Belt, 14 in. wide x 100 ft long, 1/2 hp, 15 tons/hr, 100 ft/min	17,300
13. Conveyor-elevator, live anthracite feed	1	Pivoted buckets, 5 in. x 5-1/2 in. x 3 in., 7-1/2 hp, 100 ft vertical, 45 ft horizontal, 15 tons/hr, 75 ft/min	31,000
14. Bin, anthracite feed	1	18 ft dia x 24 ft straight side, 6,100 ft^3, w/cover, flat bottom, carbon steel (24-hr capacity)	10,100

(continued)

TABLE 19 (continued)

Item	No.	Description	Total material cost, 1979 $
15. Tank, fuel oil storage	1	24 ft dia x 25 ft high, 84,600 gal, w/cover, carbon steel (30-day capacity)	13,900
16. Pump, fuel oil	2	Centrifugal, 2 gpm, 200 ft head, 1/2 hp, carbon steel (1 operating, 1 spare)	2,300
17. Fan, air	1	1,200 aft^3/min, 12 in. static head, 5 hp	3,800
18. Reactor, Resox	3	12 ft inside length x 12 ft inside width x 9 ft straight side height, four 70° hoppers, carbon steel, refractory lined	381,600
19. Feeder, reactor discharge	12	Weigh, vibratory, 410 lb/hr, 316 stainless steel	15,400
20. Hopper, spent anthracite collection	1	18 ft dia x 9 ft deep, 45° slope, w/cover, carbon steel	4,400
21. Feeder, spent anthracite collection hopper discharge	1	Vibrating pan, 1 hp, 4,900 lb/hr	3,500
22. Conveyor, spent anthracite	1	Vibrating, 6 in. wide x 100 ft long, 3 hp, 4,900 lb/hr, carbon steel, 20 ft/min	22,000
23. Conveyor, spent anthracite	1	Belt, 14 in. wide x 550 ft long, 1 hp, 4,900 lb/hr, 20 ft/min	95,200
24. Conveyor, spent anthracite	1	Belt, 14 in. wide x 500 ft long, 1 hp, 4,900 lb/hr, 20 ft/min	86,500
25. Condenser, sulfur	1	Shell and tube type, 4,940 ft^2 316 stainless steel tubes, carbon steel shell, insulated, with mesh pad, 60 in. dia x 4 in. thick, 316 stainless steel entrainment separator	153,200

(continued)

TABLE 19 (continued)

Item	No.	Description	Total material cost, 1979 $
26. Fan, tail gas	1	16,600 aft^3/min, 60 in. static head, 250 hp	42,300
27. Incinerator	1	8 ft dia x 16 ft long, carbon steel, refractory lined	190,000
Preheater, air	1	Shell and tube type, 3,620 ft^2, 316 stainless steel tubes, refractory lined, carbon steel shell	
Fan, air	1	5,400 aft^3/min, 32 in. static head, 40 hp	
28. Waste heat boiler	1	Shell and tube type, 3,630 ft^2, 316 stainless steel tubes, carbon steel shell, insulated	126,200
Subtotal			1,436,000

Area 9--Sulfur Storage and Shipping

Item	No.	Description	Total material cost, 1979 $
1. Pit, sulfur receiving	1	10 ft wide x 10 ft long x 10 ft high, 1,000 ft^3, w/cover, carbon steel, insulated, with 100 ft^2, 1 in. Schedule 40, carbon steel pipe steam heater	6,200
2. Pump, sulfur transfer	2	Centrifugal, submerged 12 gpm, 100 ft head, 2 hp, carbon steel (1 operating, 1 spare)	2,100
3. Tank, sulfur storage	1	43 ft dia x 42 ft high, 454,400 gal, w/cover, carbon steel, insulated (30-day capacity)	86,800
Heater	1	Steam, 300 ft^2, 1,200 ft of 1 in. Schedule 40, carbon steel	
4. Pump, sulfur shipping	2	Centrifugal, 60 gpm, 100 ft head, 5 hp, steam traced and insulated, carbon steel (1 operating, 1 spare)	5,000
Subtotal			100,100

a substantial heating value. Collection and conveying equipment is provided for use of the spent anthracite in the power plant boiler.

Gas and Sulfur System--

The 40 mole % SO_2 gas from the Wellman-Lord unit is mixed with a small amount of air and the resulting mixture is heated to 750°F by direct injection of 1500°F incinerator tail gas. The air is added to provide oxygen for oxidation of both the anthracite volatiles and a small amount of anthracite required to maintain the reactor temperature. The combined gases are distributed to each reactor and flow upward through the anthracite bed. The temperature in the main reaction zone is about 1300°F. In addition to sulfur vapor, some H_2S, COS, and CS_2 are formed in the reactor. A typical reactor off-gas contains, on a molar basis, about 1% H_2S, 1% SO_2, 8% to 10% S_2, 2% to 3% CO, 20% to 25% CO_2, 40% to 50% H_2O, 20% to 25% N_2, and trace quantities of COS and CS_2. The off-gas, flowing out the top of the reactor at 650°F to 750°F, passes through a shell and tube heat exchanger to condense the sulfur product and produce 15 psig steam. Recovered sulfur, at 280°F to 310°F, is collected and pumped to storage. Uncondensed gases from the sulfur condenser are routed to an incinerator to oxidize the remaining sulfur compounds back to SO_2. No. 2 fuel oil is used as the fuel. Operation of the incinerator is controlled to provide a molar oxygen concentration of 2% and a temperature of 1500°F in the incinerator tail gas. As discussed previously, part of the incinerator tail gas is used to preheat the reactor feed gas. The remaining tail gas is used to preheat incinerator air from 80°F to 1100°F in a shell and tube heat exchanger. During startup, the incinerator tail gas is used to preheat the anthracite in the reactor. The tail gas leaving the air preheater at 1155°F is cooled to 300°F in a waste heat boiler and returned to the Wellman-Lord absorbers. The heat recovered in the waste heat boiler is used to produce 15 psig steam. Steam produced in the sulfur condenser and the waste heat boiler is used in the Wellman-Lord evaporators.

Storage Capacity

Allowances for the Wellman-Lord process raw material and in-process storage are identical in the Resox and sulfuric acid cases. Storage capacities in the Wellman-Lord process are the same as those of the Wellman-Lord/sulfuric acid process.

For the Resox unit, anthracite coal is kept in a 30-day stockpile. In-process storage capacity for anthracite is 24 hours in the anthracite feed bin. The sulfur receiving pit is capable of holding 12 hours of sulfur production and 30 days of production may be stored in the sulfur storage tank.

WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

The Wellman-Lord process used in the Wellman-Lord/Allied process is similar to the one used in the Wellman-Lord/sulfuric acid process shown in Figures 5-8. The only differences are in the quantities of sulfur and water in the off-gas and the off-gas pressure. The quantity of sulfur is 3% greater than that for the sulfuric acid case because the 96% conversion results in more sulfur being returned to the absorber. The water is reduced to 15 mole %, the practical minimum attainable, because it acts as an inert ingredient in the Allied process. The pressure of the off-gas is also increased to 24 psia because of Allied process requirements. The Wellman-Lord flow rates that differ from those of the flow rates of the sulfuric acid case are shown in Table 20.

The Allied unit produces sulfur in a two-step process. Primary reduction is by coal in a fluidized-bed reactor and secondary conversion occurs in a modified Claus unit. The fluidized-bed reduction reactor is claimed to accept any type of coal or lignite without pretreatment. Because of this ability to accommodate agglomerating and high-volatile-content coals, the reactor can use the power plant coal. All cases evaluated in this study are based on the use of the base-case power plant coal described in the premises.

The Allied process flow diagram and material balance are shown in Figure 12 and Table 21. The Allied process equipment layout is shown in Figure 13. The equipment list for the Wellman-Lord/Allied process (including Wellman-Lord equipment differing from that in Table 16) equipment list is shown in Table 22.

The Wellman-Lord/Allied process is divided into the following operating areas: materials handling, gas handling, chloride removal, SO_2 absorption, stack gas reheat, sulfate crystallization, regeneration, sulfur production and sulfur storage. All areas except sulfur production and sulfur storage are the same as those discussed in the Wellman-Lord/sulfuric acid process.

The sulfur production area contains all equipment needed by the Allied process, including coal handling equipment. All equipment needed for the storage of molten sulfur is included in the sulfur storage area.

Sulfur Production Area

Coal System--

Coal is removed from the power plant stockpile into trenched hoppers and transported by belt conveyors to the raw coal feed bin. The coal is then processed in coal drying and grinding facilities to produce a pulverized and partially dried product. The coal is first ground in an impact mill that is swept with inert gas. Considerable heat which is evolved during the grinding process is used to dry the coal. For the base-case evaluation, the moisture content of the power plant coal is reduced from about 10% to about 5%. The inert gas stream absorbs the released moisture and conveys the ground coal out of the mill. The coal

TABLE 20. WELLMAN-LORD PROCESS

BASE CASE MATERIAL BALANCE

FOR ALLIED CHEMICAL COAL/SO_2 REDUCTION CASE

(Refer to Table 7)

	Stream No.	11	12	43	63	65
	Description	Gas to stack	Steam to reheater	Cooling water to condensers	Allied plant tail gas to plenum	SO_2-rich gas to Allied plant
1	Total stream (lb/hr)	5,120,900	78,800	4,853,900	29,300	20,700
2						
3						
4	Sft^3/min (60°F)	1,129,800			5,700	2,300
5	Temperature (°F)	134	470	80	300	465
6	Pressure (psia)		515			24
7	Gpm			9,700		
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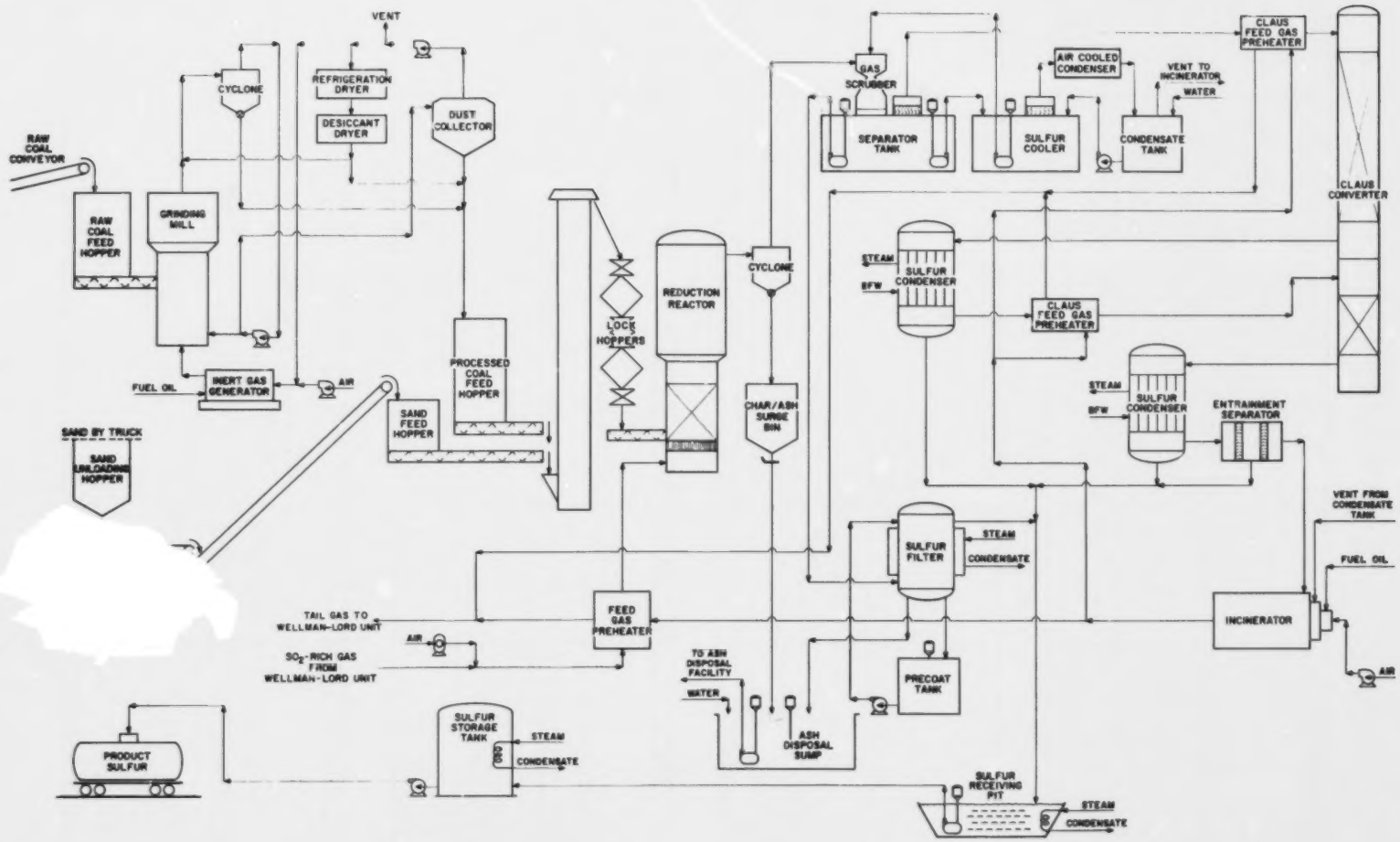

Figure 12. Allied Chemical coal/SO_2 reduction unit flow diagram.

TABLE 21. ALLIED CHEMICAL COAL/SO_2 REDUCTION UNIT

BASE CASE MATERIAL BALANCE

	Stream No.	1	2	3	4	5
	Description	Raw coal to bin	Processed coal to bin	Sand to reduction reactor	Combined solids to reduction reactor	Gas from Wellman-Lord unit
1	Total stream, lb/hr	8,300	7,500	50	7,550	20,700
2						
3						
4	Sft^3/min (60°F)					2,300
5	Temperature, °F					465
6	Pressure, psia					24
7	Gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	6	7	8	9	10
	Description	Air to reduction reactor	Gas to preheater	Gas to reduction reactor	Gas to cyclone	Gas to scrubber
1	Total stream, lb/hr	1,900	22,600	22,600	30,100	28,100
2						
3						
4	Sft^3/min (60°F)	400	2,700	2,700	4,200	4,200
5	Temperature, °F	185	430		1,800	1,800
6	Pressure, psia	24				
7	Gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	11	12	13	14	15
	Description	Gas to first claus feed preheater	Molten sulfur to scrubber	Molten sulfur to sulfur cooler	Steam to condenser	Condensate to tank
1	Total stream, lb/hr	19,500	1,603,300	1,603,300	17,600	17,600
2						
3						
4	Sft^3/min (60°F)	3,400			6,200	
5	Temperature, °F					
6	Pressure, psia					
7	Gpm		1,800	1,800		35
8	Specific gravity		1.78	1.78		
9	pH					
10	Undissolved solids, %					

	Stream No.	16	17	18	19	20
	Description	Water to sulfur cooler	Gas to first stage claus converter	Gas to first sulfur condenser	Gas to second claus feed preheater	Gas to second stage claus converter
1	Total stream, lb/hr	17,600	19,500	19,500	18,100	18,100
2						
3						
4	Sft^3/min (60°F)		3,400	3,400	3,300	3,300
5	Temperature, °F		425	580	315	425
6	Pressure, psia					
7	Gpm	35				
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

(continued)

TABLE 21 (continued)

	Stream No.	21	22	23	24	25
	Description	Gas to second sulfur condenser	Gas to incinerator	Incinerator tail gas	Incinerator gas to first claus feed preheater	Incinerator gas to second claus feed preheater
1	Total stream, lb/hr	18,100	17,700	29,300	3,100	3,600
2						
3						
4	Sft^3/min (60°F)	3,300	3,300	5,700	600	700
5	Temperature, °F	460	295	1,500	1,500	1,500
6	Pressure, psia					
7	Gpm					
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	26	27	28	29	30
	Description	Incinerator gas to reduction reactor feed gas preheater	Recombined tail gas to waste heat boiler	Tail gas to SO_2 absorber	Water to waste sump and condensate tank	Cyclone waste to disposal sump
1	Total stream, lb/hr	22,700	29,300	29,300	31,200	1,900
2						
3						
4	Sft^3/min (60°F)	4,400	5,700	5,700		
5	Temperature, °F	1,500	1,015	300	110	
6	Pressure, psia					
7	Gpm				60	
8	Specific gravity					
9	pH					
10	Undissolved solids, %					

	Stream No.	31	32	33	34	35
	Description	*Filter cake to disposal	Waste to ash pond	Molten sulfur to sulfur filter	Fuel oil to incinerator	Air to incinerator
1	Total stream, lb/hr	6,320	34,600	8,700	300	11,200
2						
3						
4	Sft^3/min (60°F)					2,500
5	Temperature, °F			310		80
6	Pressure, psia					
7	Gpm		60	10	1	
8	Specific gravity		1.1	1.78	0.87	
9	pH					
10	Undissolved solids, %		10	10		

	Stream No.	36	37	38	39	40
	Description	Steam to filter, storage tank, and receiving pit	Condensate to second sulfur condenser	Steam from second sulfur condenser	Condensate to first sulfur condenser	Steam from first sulfur condenser
1	Total stream, lb/hr	3,000	850	850	1,560	1,560
2						
3						
4	Sft^3/min (60°F)					
5	Temperature, °F	298	165	260	165	275
6	Pressure, psia	65		35		45
7	Gpm		2		3	
8	Specific gravity		1		1	
9	pH					
10	Undissolved solids, %					

*Intermittent stream: 24-hour average rate is 1,580 lb/hr.

(continued)

TABLE 21 (continued)

	Stream No.	41	42	43	44	45
	Description	Air to inert gas generator	Fuel oil to inert gas generator	Condensate to waste heat boiler	Steam from waste heat boiler	Sulfur from second sulfur condenser
1	Total stream, lb/hr	1,600	100	5,640	5,640	350
2						
3						
4	Sft^3/min (60°F)	50				
5	Temperature, °F	80		165	298	280
6	Pressure, psia				65	
7	Gpm		0.2	10		0.4
8	Specific gravity		0.87			1.78
9	pH					
10	Undissolved solids, %					

	Stream No.	46	47	48		
	Description	Sulfur from first sulfur condenser	Sulfur from sulfur filter	Sulfur to storage		
1	Total stream, lb/hr	1,400	7,120	8,870		
2						
3						
4	Sft^3/min (60°F)					
5	Temperature, °F	280	290			
6	Pressure, psia					
7	Gpm	1.5	8	10		
8	Specific gravity	1.78	1.78	1.78		
9	pH					
10	Undissolved solids, %					

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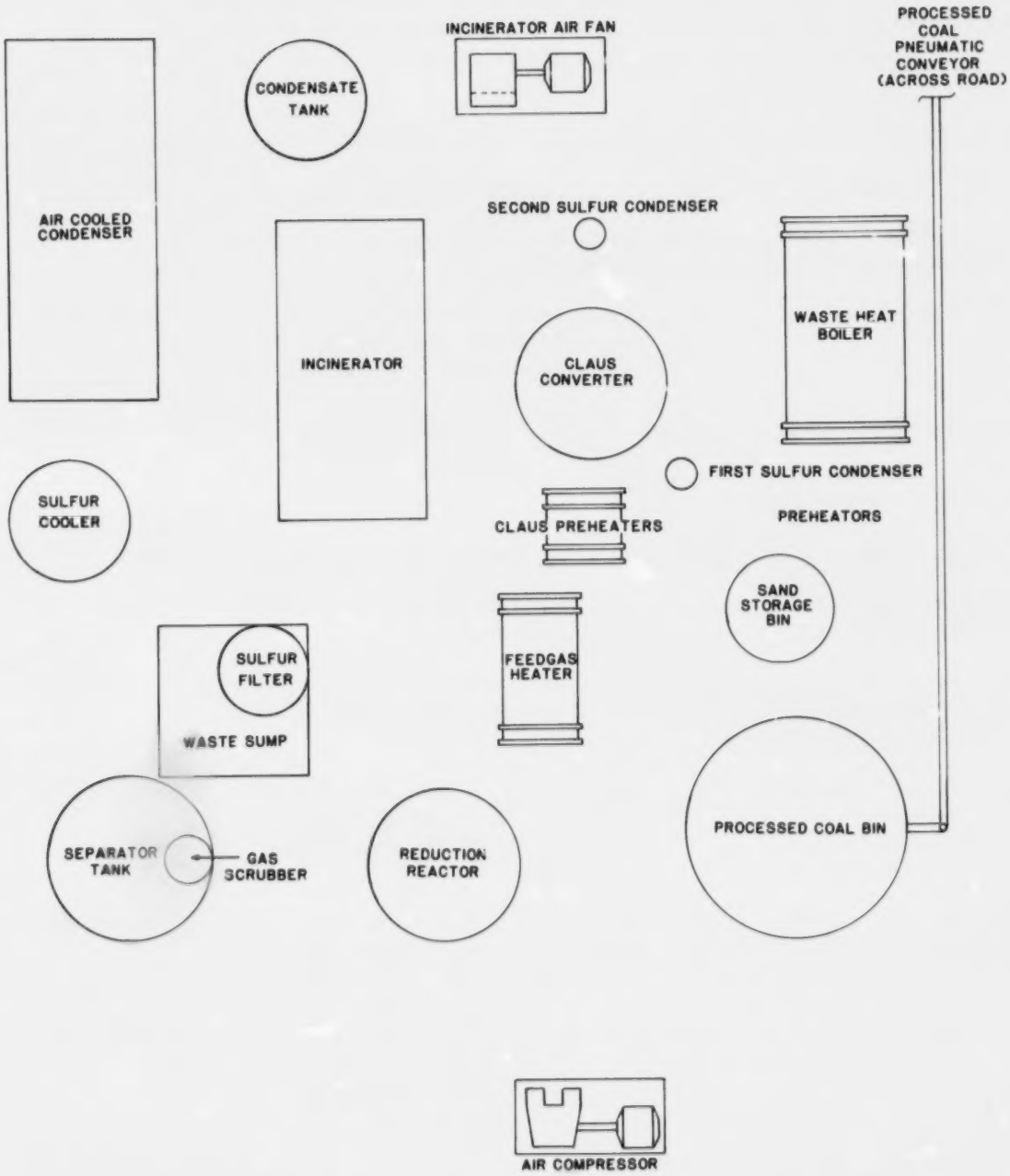

Figure 13. Allied Chemical coal/SO_2 reduction unit layout drawing.

TABLE 22. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

BASE-CASE EQUIPMENT LIST

Areas 1-4 and Area 6 have the same equipment and costs as those for the Wellman-Lord/sulfuric acid process shown in Table 11.

Area 5--Reheat

Item	No.	Description	Total material cost, 1979 $
All equipment items, descriptions, and costs are identical to Wellman-Lord/sulfuric acid process except for:			
1. Reheaters	4	Steam, tube type, 3,140 ft^2, one-half tubes made of Inconel 625 and one-half made of Cor-Ten	917,200
Subtotal			917,200

Area 7--Regeneration

Item	No.	Description	Total material cost, 1979 $
All equipment items, descriptions, and costs are identical to Wellman-Lord/sulfuric acid process except for:			
18. Condenser, secondary	2	Shell and tube type, 4,310 ft^2, 316 stainless steel tubes, heads, and shell	115,200
19. Pump, cooling water	4	Centrifugal, 4,850 gpm, 150 ft head, 400 hp, carbon steel, neoprene lined (2 operating, 2 spares)	130,600
20. Blower, product gas	1	Centrifugal, single stage, 2,280 sft^3/min, 600 hp, 316 stainless steel	161,900
Subtotal			3,497,100

(continued)

TABLE 22 (continued)

Area 8--Sulfur Production (Allied Chemical Coal/SO_2 Reduction Plant)

	Item	No.	Description	Total material cost, 1979 $
1.	Hopper, raw coal reclaim	2	2 ft 4 in. x 2 ft 4 in., 4 ft deep, 60° slope, carbon steel	11,200
2.	Feeder, raw coal storage	2	Vibrating pan, 1 hp, 13 tons/hr	7,000
3.	Pump, tunnel sump	2	Vertical, 60 gpm, 70 ft head, 5 hp, carbon steel, neoprene lined (1 operating, 1 spare)	3,400
4.	Conveyor, raw coal feed	1	Belt, 14 in. wide x 100 ft long, 1/2 hp, 13 tons/hr, 100 ft/min	17,300
5.	Conveyor, raw coal feed (incline)	1	Belt, 14 in. wide x 500 ft long, 3 hp, 8° slope, 13 tons/hr, 100 ft/min	98,800
6.	Bin, raw coal feed	1	15 ft dia x 23 ft straight side, 4,060 ft^3, w/cover, 60° cone hopper, carbon steel (24-hour capacity)	9,500
7.	Feeder, raw coal bin discharge	1	Screw, 10 in. dia x 30 ft long, 2 hp, 5 tons/hr	20,800
8.	Coal processing facilities	1	Fluid bed roller mill system, 5 tons/hr, equipment includes: inert gas generator, feeders, mill cyclone collector, bag filter, refrigeration dryer, dessicant dryer, pneumatic conveyor, all motors and duct-work	328,500
9.	Tank, fuel oil storage	1	20 ft dia x 19 ft high, 44,700 gal, w/cover, carbon steel (30-day capacity)	9,300
10.	Pump, fuel oil	2	Centrifugal, 1 gpm, 200 ft head, 1/2 hp, carbon steel (1 operating, 1 spare)	2,300

(continued)

TABLE 22 (continued)

Item	No.	Description	Total material cost, 1979 $
11. Bin, processed coal storage	1	15 ft dia x 21 ft straight side, 3,710 ft^3, w/cover, 60° cone hopper, carbon steel (24-hour capacity)	8,800
12. Feeder, processed coal bin discharge	1	Weigh, screw, 9 in. dia x 25 ft long, 1 hp, 4 tons/hr	17,500
13. Conveyor, sand	1	Pneumatic, positive pressure conveying system, 2 tons/hr, 10 hp	25,000
14. Bin, sand storage	1	7 ft dia x 11 ft straight side, 420 ft^3, w/cover, 60° cone hopper, carbon steel (30-day capacity)	1,200
15. Feeder, sand bin discharge	1	Weigh, screw, 2 in. dia x 15 ft long, 1/4 hp, 50 lb/hr	7,100
16. Elevator, processed coal	1	Continuous, bucket, 8 in. x 5-1/2 in. x 7-3/4 in., 3 hp, 45 ft lift, 4 tons/hr, 150 ft/min	10,000
17. Bin, lock	2	5 ft dia x 8 ft straight side, 160 ft^3, w/cover, 60° cone hopper, 316L stainless steel (1-hour capacity each)	45,000
18. Conveyor, reactor feed	1	Screw, 9 in. dia x 10 ft long, 1 hp, 4 tons/hr, 316 stainless steel	50,000
19. Reactor, reduction	1	7 ft dia bed, 10 ft dia above bed, 8 ft bed depth, 41 ft overall height, 1/2 in. carbon steel, refractory lined	200,000
20. Heater, feed gas	1	Shell and tube type, 2,530 ft^2, 316L stainless steel tubes, refractory lined carbon steel shell	87,800
21. Blower, air	1	Centrifugal, single stage, 420 sft^3/min, 20 hp	45,000

(continued)

TABLE 22 (continued)

	Item	No.	Description	Total material cost, 1979 $
22.	Cyclone, reduction reactor	1	15,400 aft^3/min, carbon steel, refractory lined	35,000
23.	Scrubber, gas	1	Ejector-venturi, 30 in. dia x 20 ft overall height, 316 stainless steel	15,000
24.	Tank, separator	1	11 ft dia x 11 ft high, 7,820 gal, w/cover, 316L stainless steel, insulated (3-minute capacity)	60,300
	Mist eliminator	1	Mesh pad, 32 in. dia x 4 in. thick, 316 stainless steel	
	Heater	1	Steam, 100 ft^2, 400 ft of 1 in. Schedule 40, 316 stainless steel	
25.	Pump, sulfur transfer	2	Centrifugal, submerged, 1,800 gpm, 60 ft head, 125 hp, 316 stainless steel (1 operating, 1 spare)	36,600
26.	Cooler, sulfur	1	8 ft dia x 8 ft high, 3,010 gal, w/cover, 3/8 in. 316L stainless steel, insulated (1-minute capacity)	55,300
	Mist eliminator	1	Mesh pad, 42 in. dia x 4 in. thick, 316 stainless steel	
	Heater	1	Steam, 100 ft^2, 400 ft of 1 in. Schedule 40, 316 stainless steel	
27.	Pump, sulfur	2	Centrifugal, submerged, 1,800 gpm, 100 ft head, 200 hp, 316 stainless steel (1 operating, 1 spare)	44,800
28.	Condenser, steam	1	Air cooled, 25,000 ft^2 outside surface area, 316L stainless steel tubes, w/aluminum fins	40,000
	Fan, air	2	95,000 aft^3/min, 1 in. static head, 25 hp	
29.	Tank, condensate	1	8 ft dia x 8 ft high, 3,010 gal, w/cover, 318 in. 316L stainless steel, insulated (1-hour capacity)	27,800

(continued)

TABLE 22 (continued)

	Item	No.	Description	Total material cost, 1979 $
30.	Pump, condensate tank	2	Centrifugal, submerged 35 gpm, 60 ft head, 2 hp, 316 stainless steel (1 operating, 1 spare)	5,600
31.	Pump, sulfur filter feed	2	Centrifugal, submerged, 10 gpm, 150 ft head, 2 hp, 316 stainless steel (1 operating, 1 spare)	5,600
32.	Filter, sulfur	1	Pressure leaf, 60 in. dia x 11 ft long, 800 ft^2, 316 stainless steel, insulated, steam jacketed	155,500
33.	Preheater, first Claus feed gas	1	Shell and tube type, 180 ft^2, 316L stainless steel tubes, refractory lined carbon steel shell	34,700
34.	Preheater, second Claus feed gas	1	Shell and tube type, 210 ft^2, 316L stainless steel tubes, refractory lined carbon steel shell	37,900
35.	Converter, Claus	1	9-1/2 ft inside dia x 30 ft high, 5/8 in. carbon steel shell, 1/2 in. 304 stainless steel Catalytic grids, insulated	39,500
36.	Condenser, first sulfur	1	Shell and tube type, 710 ft^2, insulated	20,400
37.	Condenser, second sulfur	1	Shell and tube type, 520 ft^2, insulated	16,500
	Mist eliminator	1	Mesh pad, 32 in. dia x 4 in. thick, 316 stainless steel	
38.	Incinerator	1	5 ft dia x 16 ft long, carbon steel, refractory lined	89,800
	Fan, air	1	2,600 aft^3/min, 17 in. static head, 10 hp	
39.	Boiler, waste heat	1	Shell and tube type, 1,100 ft^2, 316L stainless steel tubes and heads, carbon steel shell, insulated	66,300

(continued)

TABLE 22 (continued)

	Item	No.	Description	Total material cost, 1979 $
40.	Sump, waste	1	10 ft x 10 ft x 10 ft deep, concrete, tile lined, grating covered	16,200
41.	Agitator, waste sump	1	48 in. dia, 7-1/2 hp, neoprene coated	12,000
42.	Pump, waste	2	Centrifugal, submerged, 100 gpm, 150 ft head, 10 hp, carbon steel, neoprene lined (1 operating, 1 spare)	5,800
	Subtotal			1,826,100

Area 9--Sulfur Storage and Shipping

	Item	No.	Description	Total material cost, 1979 $
1.	Pit, sulfur receiving	1	10 ft wide x 10 ft long x 10 ft high, 1,000 ft^3, w/cover, carbon steel, insulated	6,200
	Heater	1	Steam, 100 ft^2, 400 ft of 1 in. Schedule 40, carbon steel	
2.	Pump, sulfur	2	Centrifugal, submerged, 12 gpm, 100 ft head, 2 hp, carbon steel (1 operating, 1 spare)	2,100
3.	Tank, sulfur storage	1	42 ft dia x 42 ft high, 435,300 gal, w/cover, carbon steel, insulated (30-day capacity)	85,500
	Heater	1	Steam, 300 ft^2, 1,200 ft of 1 in. Schedule 40, carbon steel	
4.	Pump, sulfur shipping	2	Centrifugal, 60 gpm, 100 ft head, 5 hp, steam traced and insulated, carbon steel (1 operating, 1 spare)	5,000
	Subtotal			98,800

is removed from the gas stream by a cyclone separator followed by a bag filter and is delivered to the processed coal storage bin. Some moisture-laden inert gas is vented to the atmosphere and the remainder is dried. A portion of the dried gas is used to provide a dry, inert atmosphere in the processed coal storage bin and handling equipment. The inert atmosphere prevents hydration of the dried coal and reduces the potential explosion hazard. The rest of the dried gas is recycled through the grinding mill. The inert gas is produced by burning No. 2 fuel oil under controlled combustion conditions.

Reactor Section--

Silica sand is used as the inert material in the fluidized-bed reduction reactors. A small amount of sand is entrained in the gas stream leaving the reactors. It is therefore necessary to feed sand to the reactors to replenish losses. Sand is delivered by truck and pneumatically conveyed to a 30-day storage bin. From the storage bin, sand is supplied to the process as it is needed.

Allied specifies a lock hopper system to feed material into the 24 psia atmosphere within the reduction reactor. This system consists of two vertically aligned bins situated above an enclosed screw feeder. Dried coal and makeup sand are elevated to the top bin. Gas-tight gates below this bin enable it to be filled while feeding from the second bin into the reduction reactor at a controlled rate using a screw feeder. Before transferring from the upper bin to the lower bin, a gas-tight valve above the top bin is closed and the vessel is pressurized to 24 psia. After transferring to the bottom bin, the gates between the bins are closed and the pressure in the empty upper bin is relieved before opening the top valve and recharging the depleted bin.

A small quantity of air is mixed with the 85 mole % SO_2 stream from the Wellman-Lord unit to provide oxygen for oxidation of both the volatiles and enough coal to maintain the reactor temperature. The combined feed gases are preheated in a shell and tube heat exchanger by the incinerator tail gas. From the preheater, the air-SO_2 mixture is routed to the reduction reactor where it fluidizes the bed of coal and sand.

In the reactor about 75% to 80% of the inlet SO_2 is reduced to elemental sulfur by reaction with coal at a temperature between 1500°F and 1800°F. The freeboard section of the reactor above the fluidized bed is enlarged to reduce the gas velocity and thus minimize the amount of partially reacted coal particles and sand escaping in the off-gas from the reactor. The increased contact time between the coal particles and the SO_2 gas also increases the efficiency of coal utilization. The coal addition rate is not a function of carbon content alone, but is dependent upon both the carbon and hydrogen content of the coal. For the particular coal used in this evaluation, carbon and hydrogen addition rates are roughly 1.3 moles of carbon and 1.1 moles of hydrogen per mole of SO_2.

The off-gas leaving the top of the reduction reactor contains entrained unreacted coal particles, ash, and sand. A typical molar

composition for the off-gas is roughly 15% S_2, 7% H_2S, 1% H_2, 18% H_2O, 7% N_2, 3% CO, 3.5% SO_2, 1% COS, 55.5% CO_2, and trace amounts of CS_2 and HCl. The HCl is present in an amount determined by the chloride content of the coal. The reduction reactor off-gas is passed through a cyclone separator to remove the larger particulate matter, which is dumped into an effluent sump. The partially cleaned gas is passed through an ejector-venturi where the gas is contacted cocurrently with a recirculating stream of molten sulfur. The ejector-venturi removes the remaining particulate matter, cools the gas, and condenses the sulfur in the gas. The cleaned, cooled gas and liquid sulfur are passed to a separator tank from which the gas is routed to the Claus converter feed gas preheater. A mesh pad entrainment separator in the separator tank prevents carryover of sulfur mist.

Sulfur is withdrawn from the separator tank and the particulate matter is removed in a steam-heated, pressure-leaf filter. After filtration, the molten sulfur is pumped to a sulfur storage tank. The filter cake is dumped into the effluent sump. The cyclone separator waste and the filter waste from the effluent sump are slurried and discarded in the power plant fly ash pond.

The remainder of the sulfur collected in the separator tank is pumped to a sulfur cooling tank where heat absorbed from the gas stream is removed by vaporization of water injected directly into the tank. The cooled sulfur is recirculated to the ejector-venturi. Steam from the sulfur cooler is condensed in an air cooled condenser, collected in the condensate tank, and returned at a controlled rate to the sulfur cooler. The condensate tank is vented to the incinerator for removal of noncondensables. A small amount of water is added to the condensate tank to replenish water lost in the vent stream.

The gas from the ejector-venturi is routed to a two-stage Claus conversion unit where the H_2S and SO_2 react to produce sulfur. Overall Allied plant conversion of SO_2 to sulfur is increased to about 96% in the Claus unit. However, actual recovery of sulfur product is only 90% of the sulfur in the SO_2 fed to the Allied plant because the waste streams from the sulfur filter and cyclone separator contain some sulfur.

The Claus unit consists of two shell and tube feed gas preheaters, two vertical shell and tube sulfur condensers, and a two-bed catalytic reactor. Process gas, preheated to 425°F, enters the top of the reactor vessel, travels downward through a bed of alumina catalyst, and leaves the first stage at 580°F. In the first-stage sulfur condenser, gas from the first catalyst bed is cooled to 315°F in the tubes and 30 psig steam is produced in the shell. The gas is then preheated to 425°F before entering the second-stage catalyst bed. The second-step condenser cools the gas stream from 460°F to 295°F and produces 20 psig steam. Sulfur condensed in the two condensers is collected and pumped to a sulfur storage tank. A mesh pad mist eliminator removes sulfur droplets from the gas stream as it flows from the second-stage condenser to the incinerator.

The incinerator uses No. 2 fuel oil. It is controlled to produce a tail gas with a molar oxygen concentration of 2% to insure complete oxidation of sulfur compounds to SO_2. The 1500°F incinerator tail gas is used to preheat feed gas to both stages of the Claus unit and to preheat feed gas to the reduction reactors. During startup, the tail gas is used to preheat the coal-reduction reactors. After passing through the preheaters, the tail gas is passed to a waste heat boiler where the gas is cooled from 1015°F to 300°F and produces 50 psig steam. The cooled tail gas is recycled to the SO_2 absorber. Steam produced by the waste heat boiler and sulfur condensers is used to heat the sulfur lines, the sulfur storage vessels, and the sulfur filter, with the remainder to be used in the Wellman-Lord evaporators.

Storage Capacity

Allowances for the Wellman-Lord process raw material and in-process storage are discussed in the Wellman-Lord/sulfuric acid section. For the Allied process, no allowance is made for a raw coal stockpile. It is assumed that coal can be removed from the power plant stockpile. In-process coal storage capacity is 24 hours in the raw coal bin and 24 hours in the processed coal bin. Sand is stored in a 30-day-capacity bin and there is no intermediate storage. The sulfur receiving pit is capable of holding 12 hours of sulfur production. The sulfur storage tanks have a 30-day capacity. The separation tank, sulfur cooler, and condensate tank have residence times of 4 minutes, 1 minute, and 90 minutes respectively.

RESULTS

Detailed capital investment, annual revenue requirement, and lifetime revenue requirement analyses are shown in the appendix for each of the processes. Capital investment is based on mid-1979 costs. Annual revenue requirements are based on a 7000 hr/yr operating schedule and mid-1980 costs. The lifetime revenue requirements are based on a declining operating schedule and costs discounted at 11.6% to mid-1980. All revenue requirements include credits for the applicable byproduct sulfur, sulfuric acid, sodium sulfate, and spent anthracite. Energy requirements for the base-case conditions of each process are also assessed in the discussion.

CAPITAL INVESTMENT

Capital investment summaries for each of the processes are shown in Tables 23-26. In overall comparisons, the ACP has the lowest capital investment for cases involving new (30 years of remaining life) power plants, followed, in order of increasing capital investment, by the sulfuric acid, Resox, and Allied variations of the Wellman-Lord process. The range of capital investments is not large, however. For the base case the maximum difference is 18%. For the case variations the maximum difference is 28%.

For the case variations involving existing power plants (those with 20 or 25 years of remaining life) a somewhat different situation prevails. The relative capital investment relationships of the Wellman-Lord processes remain the same. The capital investments of the ACP, however, are higher than the capital investments of the corresponding Wellman-Lord/sulfuric acid process. The range of capital investments for the four processes is less for the exisitng plant case variations than for the new-plant cases; the minimum difference is 5% and the maximum is 11%.

The relatively higher ACP capital investment for existing plants occurs because no ESP credit is given. The ESP's required for fly ash removal are assumed to be already installed in existing plants, whereas a credit is given new (that is, not yet constructed) power plants because separate ESP's for fly ash collection are not required. In existing plants the existing ESP's replace the cyclone collectors. The more efficient fly ash removal also decreases the regeneration area filtration requirements somewhat, allowing smaller sizes of filtration equipment to be used.

TABLE 23. AQUEOUS CARBONATE PROCESS

CAPITAL INVESTMENT

Case	Years remaining life[a]	Capital investment, k$	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu-heat-input allowable emission			
200 MW, 3.5% sulfur	20	34,841	174
200 MW, 3.5% sulfur	30	30,670	153
500 MW, 3.5% sulfur	25	68,249	136
500 MW, 2.0% sulfur	30	43,583	87
• 500 MW, 3.5% sulfur	30	59,702	119
500 MW, 5.0% sulfur	30	71,410	143
1,000 MW, 3.5% sulfur	25	109,563	110
1,000 MW, 3.5% sulfur	30	93,161	93
90% SO_2 removal			
500 MW, 3.5% sulfur	30	62,886	126
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu-heat-input allowable emission			
500 MW, 2.5% sulfur	25	49,199	98

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE 24. WELLMAN-LORD/SULFURIC ACID PROCESS

CAPITAL INVESTMENT

Case	Years remaining life[a]	Capital investment, k$	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu-heat-input allowable emission			
200 MW, 3.5% sulfur	20	34,207	171
200 MW, 3.5% sulfur	30	33,578	168
500 MW, 3.5% sulfur	25	66,227	132
500 MW, 2.0% sulfur	30	51,633	103
• 500 MW, 3.5% sulfur	30	65,360	131
500 MW, 5.0% sulfur	30	76,779	154
1,000 MW, 3.5% sulfur	25	103,691	104
1,000 MW, 3.5% sulfur	30	101,411	101
90% SO_2 removal			
500 MW, 3.5% sulfur	30	68,475	137
Wet-scrubbing fly ash removal	30	58,178	116
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu-heat-input allowable emission			
500 MW, 2.5% sulfur	25	40,379	81

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE 25. WELLMAN-LORD/RESOX PROCESS

CAPITAL INVESTMENT

Case	Years remaining life[a]	Capital investment, k$	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu-heat-input allowable emission			
200 MW, 3.5% sulfur	20	36,119	181
200 MW, 3.5% sulfur	30	35,447	177
500 MW, 3.5% sulfur	25	69,690	139
500 MW, 2.0% sulfur	30	53,627	107
500 MW, 3.5% sulfur	30	68,771	138
500 MW, 5.0% sulfur	30	81,371	163
1,000 MW, 3.5% sulfur	25	109,166	109
1,000 MW, 3.5% sulfur	30	106,776	107
90% SO_2 removal			
500 MW, 3.5% sulfur	30	72,198	144
Lower (90% of base case) sulfur conversion factor	30	71,240	142
Wet-scrubbing fly ash removal	30	61,641	123
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu-heat-input allowable emission			
500 MW, 2.5% sulfur	25	42,324	85

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE 26. WELLMAN-LORD/ALLIED CHEMICAL COAL/

SO_2 REDUCTION PROCESS

CAPITAL INVESTMENT

Case	Years remaining life[a]	Capital investment, k$	$/kW
Coal-Fired Power Unit			
1.2 lb SO_2/MBtu-heat-input allowable emission			
200 MW, 3.5% sulfur	20	37,994	190
200 MW, 3.5% sulfur	30	37,428	187
500 MW, 3.5% sulfur	25	71,167	142
500 MW, 2.0% sulfur	30	55,578	111
• 500 MW, 3.5% sulfur	30	70,338	141
500 MW, 5.0% sulfur	30	82,323	165
1,000 MW, 3.5% sulfur	25	109,247	109
1,000 MW, 3.5% sulfur	30	107,148	107
90% SO_2 removal 500 MW, 3.5% sulfur	30	73,643	147
Lower (90% of base case) sulfur conversion factor	30	72,655	145
Wet-scrubbing fly ash removal	30	63,217	126
Oil-Fired Power Unit			
0.8 lb SO_2/MBtu-heat-input allowable emission			
500 MW, 2.5% sulfur	25	44,074	88

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

This comparison is illustrative of the economic benefits derived from the combination of flue gas cleaning functions, one of the main advantages of the ACP in these studies. The Wellman-Lord process case variations in which chloride and fly ash removal are combined offer a similar example. In the case of the ACP and similar dry-collection FGD processes, however, particulate collection and chloride removal are intrinsic functions, not process options.

For further cost comparisons, the direct capital investment costs by processing area are shown in Tables 27 and 28. Table 27 shows the base case and the 2.0% and 5.0% coal sulfur content case variations. Since the power plants are new, an ESP credit is applied to the ACP. Table 28 shows the 200-, 500-, and 1000-MW existing power plants for which no ESP credit is applied to the ACP. The materials handling area costs are minor and essential equivalent for all of the processes. Gas handling is slightly higher for the ACP than for the Wellman-Lord processes because of the additional ductwork required for the ESP's. Chloride removal is a substantial cost element in the Wellman-Lord processes, accounting in the base cases for about 15% of the process equipment costs, similar to the costs for SO_2 absorption. Absorption-collection process equipment costs for the ACP are about twice that of the Wellman-Lord processes but the costs include ESP's as well as the spray dryer absorbers. When ESP credits are applied, the ACP absorption-collection cost is essentially equivalent to those of the Wellman-Lord processes. In Tables 27 and 28, costs for flue gas reheat are included in the SO_2 absorption-collection costs for the Wellman-Lord processes. The reheat costs are 2.3 $/kW for the 500-MW power plant and 2.5 and 1.8 $/kW for the 200- and 1000-MW power plants. The ACP does not require flue gas reheating. The ACP regeneration area costs are about one-third higher than those of the Wellman-Lord processes. For the ACP, however, this area also includes the chloride purge and residual fly ash removal. The ACP also produces H_2S, which is readily convertible to sulfur. The SO_2 produced by the Wellman-Lord regeneration area requires more complicated treatment to produce a readily marketable byproduct. This is reflected in the low ACP byproduct manufacturing costs, which are about one-half those of the Wellman-Lord processes. Overall, the regeneration - byproduct manufacturing total costs are quite similar for all four processes. The two factors contributing to cost differences between the ACP and the Wellman-Lord processes are the new-plant ESP credit for the ACP and chloride removal in the Wellman-Lord processes. In Table 28, representing existing plants, the ESP credit is not applied to the ACP process and its process equipment costs are similar to the Wellman-Lord process equipment costs.

In comparisons of the three Wellman-Lord process variations, the only major capital investment cost differences are in the byproduct manufacturing areas. The different quantities of sulfur recycled in tail gas returned to the absorbers because of the different design sulfur recover efficiencies and the different Wellman-Lord off-gas compositions have a minor effect on costs of the Wellman-Lord process. The byproduct manufacturing process equipment costs are understandably lowest for the sulfuric acid unit, although the Resox and Allied units

TABLE 27. DIRECT CAPITAL INVESTMENT BY PROCESSING AREA FOR

NEW 500-MW POWER PLANTS WITH 2.0%, 3.5%, and 5.0% SULFUR COAL

	$/kW											
	ACP			Wellman-Lord/sulfuric acid			Wellman-Lord/Resox			Wellman-Lord/Allied		
	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S
Processing area												
Materials handling	0.5	0.8	1.1	0.6	0.9	1.1	0.6	0.9	1.1	0.6	0.9	1.1
Gas handling	10.2	10.2	10.2	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Chloride removal	-	-	-	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8	9.8
SO_2 absorption-collection[a]	21.3	21.3	21.3	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Fly ash collection	1.0	1.0	1.0	-	-	-	-	-	-	-	-	-
ESP credit	(11.8)	(9.4)	(9.4)	-	-	-	-	-	-	-	-	-
Regeneration[b]	16.0	27.6	37.3	12.7	21.6	29.0	12.9	21.9	29.4	12.7	21.6	29.0
Byproduct manufacture	4.4	7.5	10.0	7.6	13.0	17.5	9.3	15.9	21.3	11.4	17.6	22.3
Total process equipment	41.6	58.9	71.4	50.5	65.0	77.1	52.6	68.2	81.3	54.3	69.6	81.9
Total capital investment	87.2	119.4	142.8	103.3	130.7	153.6	107.3	137.5	162.7	111.2	140.7	164.6

a. Consists of ACP spray dryers and ESP's; Wellman-Lord absorbers and reheat costs of 2.3 $/kW.
b. Includes ACP chloride purge and residual particulate matter removal.

TABLE 28. DIRECT CAPITAL INVESTMENT COSTS BY PROCESSING AREA

FOR EXISTING 200-MW, 500-MW, and 1000-MW POWER PLANTS

	$/kW											
	ACP			Wellman-Lord/sulfuric acid			Wellman-Lord/Resox			Wellman-Lord/Allied		
	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW
Processing area												
Materials handling	1.2	0.8	0.6	1.5	0.9	0.6	1.5	0.9	0.6	1.5	0.9	0.6
Gas handling	11.3	10.3	8.1	9.8	8.9	7.0	9.8	8.9	7.0	9.8	8.9	7.0
Chloride removal	-	-	-	10.8	10.0	8.2	10.8	10.0	8.2	10.8	10.0	8.2
SO_2 absorption-collection[a]	23.4	21.7	17.9	12.0	11.2	9.4	12.0	11.2	9.4	12.0	11.2	9.4
Regeneration[b]	37.7	28.0	22.4	30.0	21.9	17.4	30.4	22.2	17.6	29.9	21.9	17.3
Byproduct manufacture	10.4	7.6	6.0	17.9	13.2	10.5	22.0	16.1	12.7	27.2	17.8	12.9
Total process capital	84.1	68.4	55.1	82.0	66.0	53.1	86.5	69.2	55.6	91.2	70.6	55.5
Total capital investment	174.2	136.5	109.6	171.0	132.5	103.7	180.6	139.4	109.2	190.0	142.3	109.2

a. Consists of ACP spray dryers and ESP's; Wellman-Lord scrubbers and reheat costs of 2.5, 2.3, and 1.8 $/kW for 200-, 500-, and 1000-MW plants.

b. Includes ACP chloride purge and residual particulate matter removal.

are only 22% and 35% higher than the sulfuric acid unit in process equipment costs. The overall FGD total capital investments for the Wellman-Lord/Resox and Wellman-Lord/Allied processes are only 5% and 7% higher than the total capital investment of the Wellman-Lord/sulfuric acid process. The higher capital investment for the Allied unit results from the use of power plant bituminous coal, requiring grinding and drying facilities, and in a more elaborate sulfur collection and cleaning facilities. The Allied unit capital investment for coal handling and processing is twice that of the anthracite handling capital investment for the Resox unit. The Allied unit capital investment for sulfur collection and processing is two-thirds higher than that of the Resox unit. Conversely, the Resox reactor capital investment, which includes spent anthracite handling, is almost twice that of the Allied unit. The higher Resox reactor costs are the result of the complex piping and extensive structural support required for the reactors and anthracite feed bins. Most of the Allied process equipment is self-supporting. The Allied unit also has a larger incremental pond cost (0.9 $/kW for the base case) representing disposal costs of the spent reducing coal.

Case Variations

The expected economy of scale is seen in the results of the power plant size case variations as shown in Figure 14. The capital investments approximately double as the power plant size increases from 200 to 500 MW and triple as the size increases from 200 to 1000 MW. The capital investment per unit of electricity produced thus decreases one-fourth and two-fourths for the two size increases. The convergence of the Resox and Allied costs at the 1000-MW power plant size is a result of scaling factors based on the process complexity. The Allied unit, with more process equipment, has a slightly higher economy of scale. Even though Allied has more process equipment, the equipment is all standard. The Resox reactor and feed bin is not a standard arrangement. The cost of the Allied grinding equipment (a major cost item) escalates little with capacity.

Coal sulfur content has a considerable effect on capital investment, as shown in Figure 15. Costs related to sulfur removal rates are more than tripled as the coal sulfur content increases from 2% to 5%. (About 3.3 times more sulfur is removed at the 5% coal sulfur content than at the 2% coal sulfur content to meet the 1.2 lb SO_2/MBtu emission limit.) The processing areas affected are the materials handling, regeneration, and byproduct manufacturing areas, which more than double in cost. The result is an increase in cost of 64% for the ACP and about 50% for the three Wellman-Lord processes as the coal sulfur level increases from 2% to 5%. The larger increase for the ACP occurs because the ACP has a larger percentage of capital equipment costs in the processing areas affected by sulfur removal rates and the ESP credit is higher for the lower sulfur level because of the lower collection efficiency with lower-sulfur flue gas.

The data in Figures 14 and 15, in conjunction with the detailed results in the appendix, can be used to develop correlations of capital

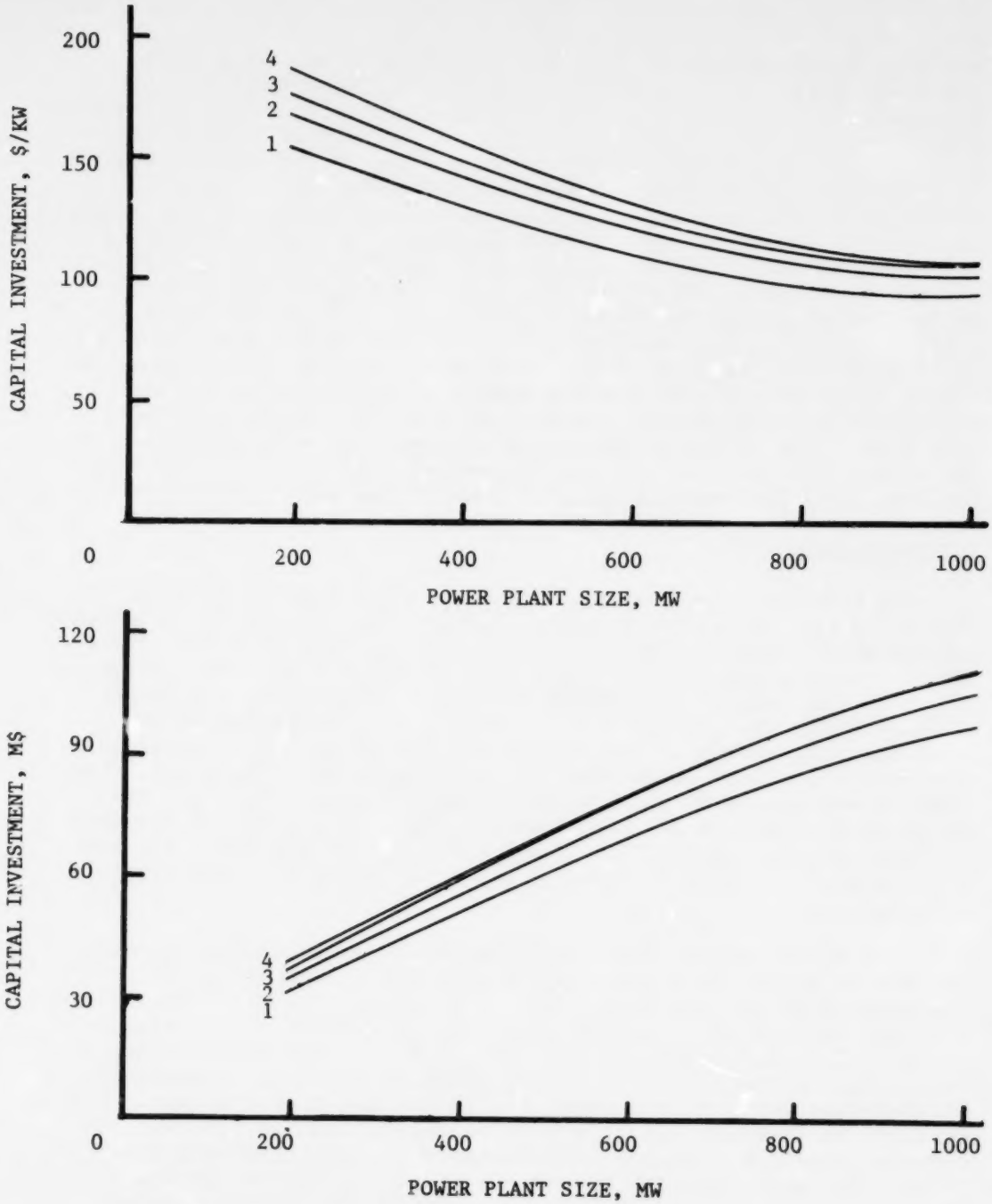

Figure 14. Effect of power plant size on capital investment. 1 - ACP, 2 - Wellman-Lord/sulfuric acid, 3 - Wellman-Lord/Resox, 4 - Wellman-Lord/Allied.

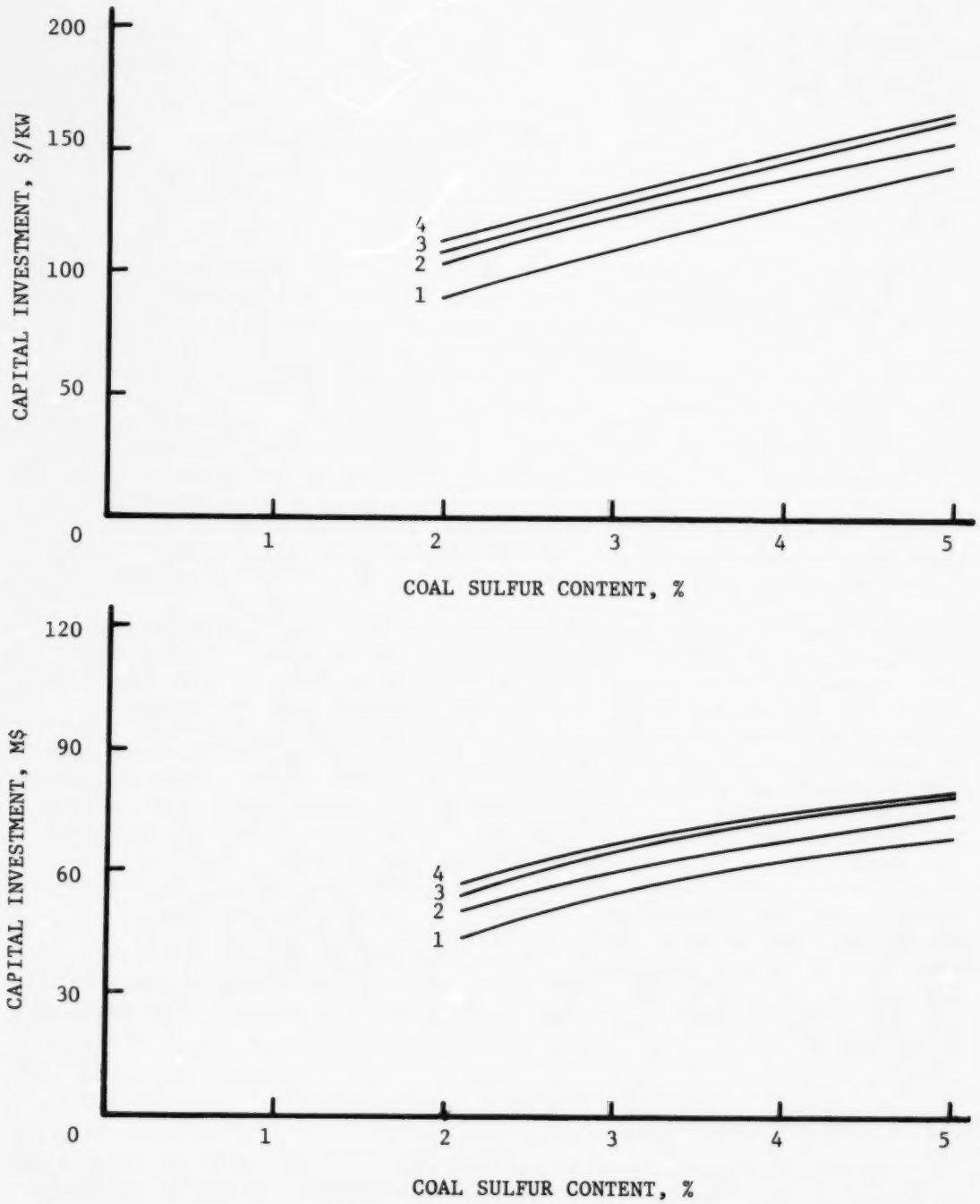

Figure 15. Effect of coal sulfur content on capital investment.
1 - ACP, 2 - Wellman-Lord/sulfuric acid, 3 - Wellman-Lord/Resox, 4 - Wellman-Lord/Allied.

investment as a function of power plant size and coal sulfur content. These correlations can be used to project the data to conditions not treated in this study.

An increase in SO_x removal efficiency from the base-case 79% to 90% results in a small increase in capital investment. The increase is about 5% for all of the processes and is a result of larger reduction, regeneration, and byproduct manufacturing costs.

Reduction of the conversion efficiencies of the Resox and Allied units by 10% of the base-case conversions (90% and 96% respectively) increases the capital investments by about 3% for both processes.

As a case variation for the Wellman-Lord processes, the chloride removal scrubbing system was modified to include fly ash removal as well. For comparison with the base-case conditions and the ACP, an ESP direct investment credit of 9.4 $/kW is applied to the wet-scrubbing fly ash removal cases as it is for the ACP. The results are shown in Table 29. The increase in capital investment for combined fly ash and chloride removal, as compared with chloride removal alone, is only 0.8 $/kW. Combining fly ash removal and chloride removal thus results in a substantial reduction in capital investment when the ESP credit is applied.

The case variation for oil-fired power plants shows a different capital investment relationship between the ACP and the three Wellman-Lord processes. The capital investments by processing area are shown in Table 30. For the oil-fired power plants, the ACP has the highest capital investment, 22% to 12% higher than the three Wellman-Lord processes. The capital investments of all four processes are lower than the corresponding existing 500-MW coal-fired power plant capital investments and the relationship of the three Wellman-Lord variations are unchanged. The lower capital investments are partially the result of the lower flue gas rate, fuel sulfur content, and low fly ash content. The major reduction of capital investment in the Wellman-Lord variations, however, results from the elimination of about 10 $/kW for chloride removal, making the absorption-collection area for the Wellman-Lord process considerably less expensive than the ACP absorption-collection area. The capital investment relationships of the four processes in other processing areas remain essentially unchanged from those of the existing coal-fired cases.

ANNUAL REVENUE REQUIREMENTS

The annual revenue requirements for the four processes are summarized in Tables 31-34. The annual revenue requirements follow the same general relationships as the capital investment. For new plants, the ACP has the lowest annual revenue requirements, followed in order of increasing cost by the Wellman-Lord/sulfuric acid, Wellman-Lord/Allied, and Wellman-Lord/Resox processes. For existing plants, the Wellman-Lord/sulfuric acid process has the lowest annual revenue requirements, followed by the ACP, the Wellman-Lord/Allied process, and the Wellman-Lord/Resox process.

TABLE 29. WELLMAN-LORD PROCESSES CAPITAL INVESTMENT WITH WET-SCRUBBING AND FLY ASH REMOVAL

	$/kW						
		Wellman-Lord/sulfuric acid		Wellman-Lord/Resox		Wellman-Lord/Allied	
	ACP base case	Base case	Wet fly ash removal	Base case	Wet fly ash removal	Base case	Wet fly ash removal
Processing area							
Materials handling	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Gas handling	10.2	8.8	9.3	8.8	9.3	8.8	9.3
Chloride removal	-	9.8	-	9.8	-	9.8	-
SO_2 absorption-collection	22.3	11.0	11.0	11.0	11.0	11.0	11.0
ESP credit	(9.4)	-	(9.4)	-	(9.4)	-	(9.4)
Fly ash-chloride removal	-	-	10.6	-	10.6	-	10.6
Regeneration	27.6	21.6	21.6	21.9	21.9	21.6	21.6
Byproduct manufacture	7.5	13.0	13.0	15.9	15.9	17.6	17.6
Total process equipment	59.1	65.0	56.9	68.2	60.1	69.6	61.5
Total capital investment	119.4	130.7	116.4	137.5	123.3	140.7	126.4

TABLE 30. CAPITAL INVESTMENT BY PROCESSING AREA

FOR OIL-FIRED POWER PLANTS

	$/kW			
	ACP	Wellman-Lord/ sulfuric acid	Wellman-Lord/ Resox	Wellman-Lord/ Allied
Processing area				
Materials handling	0.5	0.6	0.6	0.6
Gas handling	9.1	7.8	7.8	7.8
Absorption-collection	18.8	10.6	10.6	10.6
Regeneration	15.6	12.4	12.4	12.3
Byproduct manufacture	4.3	7.4	9.1	11.1
Total process capital	48.2	38.7	40.6	42.5
Total capital investment	98.4	80.7	84.6	88.1

TABLE 31. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

Case	Years remaining life[a]	Annual revenue requirements k$	Mills/ kWh	$/ton fuel ($/bbl oil)	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit						
1.2 lb SO_2/MBtu-heat-input allowable emission						
200 MW, 3.5% sulfur	20	10,010	7.15	15.80	0.75	682
200 MW, 3.5% sulfur	30	8,724	6.23	14.23	0.68	614
500 MW, 3.5% sulfur	25	18,957	5.42	12.36	0.59	533
500 MW, 2.0% sulfur	30	12,026	3.44	8.02	0.38	752
• 500 MW, 3.5% sulfur	30	16,820	4.81	11.21	0.53	484
500 MW, 5.0% sulfur	30	20,708	5.92	13.80	0.66	387
1,000 MW, 3.5% sulfur	25	30,427	4.35	10.14	0.48	437
1,000 MW, 3.5% sulfur	30	26,517	3.79	9.14	0.44	394
90% SO_2 removal						
500 MW, 3.5% sulfur	30	17,851	5.10	11.90	0.57	451
Oil-Fired Power Unit						
0.8 lb SO_2/MBtu-heat-input allowable emission						
500 MW, 2.5% sulfur	25	13,254	3.79	(2.48)	0.41	864

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE 32. WELLMAN-LORD/SULFURIC ACID

ANNUAL REVENUE REQUIREMENTS

Case	Years remaining life[a]	Annual revenue requirements				
		k$	Mills/ kWh	$/ton fuel ($/bbl oil)	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit						
1.2 lb SO_2/MBtu-heat-input allowable emission						
200 MW, 3.5% sulfur	20	9,659	6.90	15.25	0.73	658
200 MW, 3.5% sulfur	30	9,140	6.53	14.91	0.71	643
500 MW, 3.5% sulfur	25	18,415	5.26	12.01	0.57	518
500 MW, 2.0% sulfur	30	14,071	4.02	9.38	0.45	879
• 500 MW, 3.5% sulfur	30	17,892	5.11	11.93	0.57	514
500 MW, 5.0% sulfur	30	21,220	6.06	14.15	0.67	397
1,000 MW, 3.5% sulfur	25	29,464	4.21	9.82	0.47	424
1,000 MW, 3.5% sulfur	30	28,363	4.05	9.78	0.47	422
90% SO_2 removal						
500 MW, 3.5% sulfur	30	18,764	5.36	12.51	0.60	474
Wet-scrubbing fly ash removal	30	17,310	4.95	11.54	0.55	498
Oil-Fired Power Unit						
0.8 lb SO_2/MBtu-heat-input allowable emission						
500 MW, 2.5% sulfur	25	11,993	3.43	(2.24)	0.37	782

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE 33. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

Case	Years remaining life[a]	Annual revenue requirements k$	Mills/ kWh	$/ton fuel ($/bbl oil)	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit						
1.2 lb SO_2/MBtu-heat-input allowable emission						
200 MW, 3.5% sulfur	20	11,141	7.96	17.59	0.84	759
200 MW, 3.5% sulfur	30	10,558	7.54	17.22	0.82	742
500 MW, 3.5% sulfur	25	21,709	6.20	14.16	0.67	611
500 MW, 2.0% sulfur	30	15,629	4.47	10.42	0.50	977
• 500 MW, 3.5% sulfur	30	21,107	6.03	14.07	0.67	607
500 MW, 5.0% sulfur	30	26,044	7.44	17.36	0.83	487
1,000 MW, 3.5% sulfur	25	35,615	5.09	11.87	0.57	512
1,000 MW, 3.5% sulfur	30	34,303	4.90	11.83	0.56	510
90% SO_2 removal						
500 MW, 3.5% sulfur	30	22,393	6.40	14.93	0.71	565
Lower (90% of base case) sulfur conversion factor	30	22,140	6.33	14.76	0.70	637
Wet-scrubbing fly ash removal	30	20,530	5.87	13.69	0.65	590
Oil-Fired Power Unit						
0.8 lb SO_2/MBtu-heat-input allowable emission						
500 MW, 2.5% sulfur	25	13,501	3.86	(2.52)	0.42	881

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

TABLE 34. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

Case	Years remaining life[a]	Annual revenue requirements k$	Mills/ kWh	$/ton fuel ($/bbl oil)	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit						
1.2 lb SO_2/MBtu-heat-input allowable emission						
200 MW, 3.5% sulfur	20	11,277	8.05	17.80	0.85	768
200 MW, 3.5% sulfur	30	10,702	7.64	17.45	0.83	753
500 MW, 3.5% sulfur	25	21,366	6.10	13.93	0.66	601
500 MW, 2.0% sulfur	30	15,720	4.49	10.48	0.50	982
• 500 MW, 3.5% sulfur	30	20,788	5.94	13.86	0.66	598
500 MW, 5.0% sulfur	30	25,267	7.22	16.84	0.80	472
1,000 MW, 3.5% sulfur	25	34,386	4.91	11.46	0.55	494
1,000 MW, 3.5% sulfur	30	33,167	4.74	11.44	0.54	493
90% SO_2 removal						
500 MW, 3.5% sulfur	30	21,965	6.28	14.64	0.70	554
Lower (90% of base case) sulfur conversion factor	30	21,709	6.20	14.47	0.69	624
Wet-scrubbing fly ash removal	30	20,212	5.77	13.47	0.64	581
Oil-Fired Power Unit						
0.8 lb SO_2/MBtu-heat-input allowable emission						
500 MW, 2.5% sulfur	25	13,571	3.88	(2.54)	0.42	885

a. A 127,500-hour, 30-year lifetime is used. FGD facilities for cases with 30 years of remaining life are constructed simultaneously with the power plant; others are retrofit installations.

For the base case, the maximum difference in annual revenue requirements is 25%; for the case variations, the maximum difference is 30%.

The cost relationships are the result of the indirect cost capital charges based on capital investment which compose roughly half of the annual revenue requirements. The ranking of the processes by capital investment is thus imprinted upon the annual revenue requirements. In this case, the relationship of the ACP to the Wellman-Lord processes is strongly influenced by the ESP capital investment credit for new plants reflected in the indirect costs. In direct costs, consisting of raw material and conversion costs, the ACP is one-fifth to two-fifths lower than the Wellman-Lord processes.

The major cost elements in annual revenue requirements are shown in Table 35 for the base case and fuel-sulfur case variations and in Table 36 for the existing-plant power plant size case variations. The major areas of difference are in raw materials, utilities, indirect costs, and byproduct credits. Labor, supervision, and maintenance costs do not differ greatly among the four processes.

Reducing coal is the largest raw material cost for all three sulfur-producing processes, particularly for the Wellman-Lord/Resox process which uses anthracite. The ACP requires more soda ash than the Wellman-Lord processes and more reducing coal than the Wellman-Lord/Allied process, which, like the ACP, also uses power plant coal.

Utilities constitute the largest direct cost for all four processes and represent the major area of cost difference between the ACP and the Wellman-Lord processes. The ACP utility costs are less than one-half those of the Wellman-Lord processes. The ACP requires no power plant steam, has slightly lower electricity costs, and lower water costs. About one-third of the ACP utility cost is for fuel oil, however. In this study fuel oil is priced at $0.40/gal, the price used in previous evaluations in this series. At escalated fuel oil prices, the utility cost advantage of the ACP relative to the other processes would be eroded unless an alternate fuel were used. The main advantages of the ACP in utility costs, however, are its low process steam requirements and its absence of flue gas reheat requirements. In addition to larger process steam requirements, the Wellman-Lord processes require steam for flue gas reheating.

The annual revenue requirements of the three variations of the Wellman-Lord process are lowest for the sulfuric acid variation and essentially equivalent for the Resox and Allied variations. Since the Wellman-Lord costs are essentially equivalent for all three variations, the cost differences represent the byproduct manufacturing costs, indirect costs, and sales credits. Thus the sulfuric acid variation, which has no raw material costs for byproduct production, the lowest indirect costs, and the highest byproduct credit, has considerably lower annual revenue requirements than the sulfur-producing variations.

TABLE 35. ANNUAL REVENUE REQUIREMENTS PROCESS COST ELEMENTS

FOR NEW 500-MW POWER PLANTS WITH 2.0%, 3.5%, AND 5.0% SULFUR COAL

	Mills/kWh											
	ACP			Wellman-Lord/sulfuric acid			Wellman-Lord/Resox			Wellman-Lord/Allied		
	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S
Raw materials												
Soda ash	0.15	0.32	0.49	0.09	0.19	0.29	0.09	0.19	0.29	0.09	0.19	0.29
Anthracite	-	-	-	-	-	-	0.26	0.57	0.87	-	-	-
Coal	0.17	0.36	0.56	-	-	-	-	-	-	0.10	0.21	0.32
Other	-	-	-	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.02
Total	0.31	0.68	1.05	0.10	0.20	0.31	0.36	0.77	1.18	0.20	0.41	0.63
Labor and supervision	0.17	0.19	0.20	0.15	0.19	0.18	0.15	0.17	0.18	0.15	0.17	0.18
Utilities												
Fuel oil	0.12	0.26	0.41	-	-	-	0.04	0.09	0.14	0.02	0.05	0.08
Steam	-	-	-	0.54	0.89	1.24	0.54	0.90	1.25	0.54	0.90	1.25
Electricity	0.42	0.56	0.72	0.50	0.64	0.78	0.50	0.63	0.77	0.50	0.64	0.78
Water	0.01	0.02	0.03	0.08	0.18	0.26	0.07	0.14	0.21	0.08	0.14	0.22
Heat credit	(0.05)	(0.11)	(0.18)	(0.01)	(0.03)	(0.04)	(0.05)	(0.11)	(0.16)	(0.02)	(0.03)	(0.05)
Total	0.50	0.73	0.98	1.11	1.68	2.24	1.10	1.65	2.21	1.12	1.70	2.28
Maintenance and analysis	0.48	0.67	0.80	0.50	0.63	0.75	0.51	0.66	0.78	0.53	0.68	0.79
Total direct costs	1.46	2.27	3.03	1.86	2.68	3.48	2.13	3.25	4.35	2.01	2.96	3.88
Indirect costs	2.15	2.95	3.53	2.51	3.19	3.77	2.59	3.32	3.94	2.67	3.39	3.96
Byproduct credit	(0.19)	(0.41)	(0.64)	(0.35)[a]	(0.77)[b]	(1.18)[c]	(0.25)[a,d]	(0.54)[b,e]	(0.84)[c,f]	(0.19)[a]	(0.41)[b]	(0.63)[c]
Total	3.44	4.81	5.92	4.02	5.11	6.06	4.47	6.03	7.44	4.49	5.94	7.22

a. Includes 0.02 mill/kWh for Na_2SO_4.
b. Includes 0.05 mill/kWh for Na_2SO_4.
c. Includes 0.08 mill/kWh for Na_2SO_4.
d. Includes 0.06 mill/kWh for spent anthracite.
e. Includes 0.12 mill/kWh for spent anthracite.
f. Includes 0.19 mill/kWh for spent anthracite.

TABLE 36. ANNUAL REVENUE REQUIREMENT COST ELEMENTS

FOR EXISTING 200-MW, 500-MW, AND 1000-MW POWER PLANTS

	Mills/kWh											
	ACP			Wellman-Lord/sulfuric acid			Wellman-Lord/Resox			Wellman-Lord/Allied		
	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW
Raw materials												
Soda ash	0.34	0.33	0.32	0.20	0.19	0.19	0.20	0.19	0.19	0.20	0.19	0.19
Anthracite	-	-	-	-	-	-	0.60	0.58	0.57	-	-	-
Coal	0.38	0.37	0.36	-	-	-	-	-	-	0.22	0.21	0.21
Other	-	-	-	0.02	0.02	0.01	0.01	0.02	0.01	0.02	0.02	0.01
Total	0.72	0.70	0.68	0.22	0.21	0.20	0.81	0.79	0.77	0.44	0.42	0.41
Labor and supervision	0.34	0.19	0.12	0.27	0.17	0.12	0.27	0.17	0.12	0.27	0.17	0.12
Utilities												
Fuel oil	0.27	0.27	0.26	-	-	-	0.10	0.09	0.09	0.05	0.05	0.05
Steam	-	-	-	0.94	0.91	0.89	0.95	0.92	0.90	0.95	0.92	0.90
Electricity	0.65	0.58	0.55	0.73	0.66	0.62	0.72	0.65	0.61	0.73	0.66	0.62
Other	0.03	0.02	0.01	0.19	0.17	0.17	0.14	0.14	0.14	0.16	0.14	0.14
Heat credit	(0.12)	(0.12)	(0.11)	(0.03)	(0.03)	(0.03)	(0.11)	(0.11)	(0.11)	(0.04)	(0.03)	(0.03)
Total	0.83	0.75	0.71	1.83	1.71	1.65	1.80	1.69	1.63	1.85	1.74	1.68
Maintenance and analysis	1.08	0.77	0.54	0.92	0.64	0.44	0.97	0.67	0.45	1.02	0.69	0.46
Total direct costs	2.96	2.41	2.06	3.23	2.74	2.41	3.85	3.32	2.98	3.58	3.02	2.67
Indirect costs	4.63	3.43	2.71	4.48	3.31	2.56	4.68	3.44	2.66	4.91	3.50	2.65
Byproduct credit	(0.44)	(0.42)	(0.41)	(0.81)[a]	(0.78)[b]	(0.76)[c]	(0.58)[a,d]	(0.56)[b,e]	(0.55)[c,f]	(0.43)[a]	(0.42)[b]	(0.41)[c]
Total	7.15	5.42	4.35	6.90	5.26	4.21	7.96	6.20	5.09	8.05	6.10	4.91

a. Includes 0.06 mill/kWh for Na_2SO_4.
b. Includes 0.05 mill/kWh for Na_2SO_4.
c. Includes 0.05 mill/kWh for Na_2SO_4.
d. Includes 0.13 mill/kWh for spent anthracite.
e. Includes 0.13 mill/kWh for spent anthracite
f. Includes 0.12 mill/kWh for spent anthracite.

The two areas of significant cost differences between the Resox and Allied variations are in reducing coal costs and byproduct revenue. At the base-case conditions, anthracite for the Resox unit, at 0.57 mill/kWh, is appreciably more expensive than power plant coal for the Allied unit, at 0.21 mill/kWh. The byproduct credit for the Wellman-Lord/Resox process is 0.54 mill/kWh, compared with 0.41 mill/kWh for the Wellman-Lord/Allied process, because the Resox credit includes 0.12 mill/kWh for spent anthracite transferred to the power plant for boiler fuel.

Case Variations

The effect of power unit size on annual revenue requirements is shown in Figure 16. The annual revenue requirements approximately double as the power plant size increases from 200 to 500 MW and triple as the size increases from 200 to 1000 MW. In terms of mills/kWh, the corresponding decreases are about one-fourth and two-fourths. Since costs for raw materials and utilities and byproduct credits are linearly related to power plant size, the economy of scale is primarily realized through more efficient use of labor, supervision, and maintenance and reduced capital charges and overheads.

The effect of coal sulfur content is shown in Figure 17. In contrast to the effects of power unit size, coal sulfur content has little effect on labor and supervision costs. Costs directly related to sulfur removed such as raw material are more than tripled as the coal sulfur content increases from 2% to 5%. Utility, labor, supervision, and maintenance costs, related partly to sulfur removed and partly to flue gas rate, approximately double. Indirect costs increase about one-half. These cost increases are somewhat offset by a higher byproduct credit and heat credit paralleling the threefold increase in sulfur removed. The overall result is an increase in annual revenue requirements of about 70% for the ACP and 50% to 60% for the Wellman-Lord processes, depending on percentages of costs and credits linearly related to the quantity of sulfur removed. The ACP, with high raw material costs, high fuel oil costs, and a smaller byproduct credit, all of which are directly related to the quantity of sulfur removed, has the largest cost increase. The Wellman-Lord/sulfuric acid process, with low raw material costs and a large byproduct credit, has the least.

The varied rates of cost increase result in changing cost relationships as the coal sulfur content increases. The ACP annual revenue requirements converge with those of the other processes, most obviously with the Wellman-Lord/sulfuric acid process. The annual revenue requirements of the Wellman-Lord/Resox process, slightly less than those of the Wellman-Lord/Allied process with 2% sulfur coal, become slightly greater as the coal sulfur content increases. This reversal of position results from the larger costs for raw materials, particularly anthracite, for the Resox version, a cost directly related to coal sulfur content.

The annual revenue requirements for 90% SO_2 removal increase 4% to 6% compared with the base-case 79% removal. The increased costs are generally distributed through direct and indirect costs, mitigated by a 13% to 17% increase in byproduct credit from the 14% increase in sulfur removed.

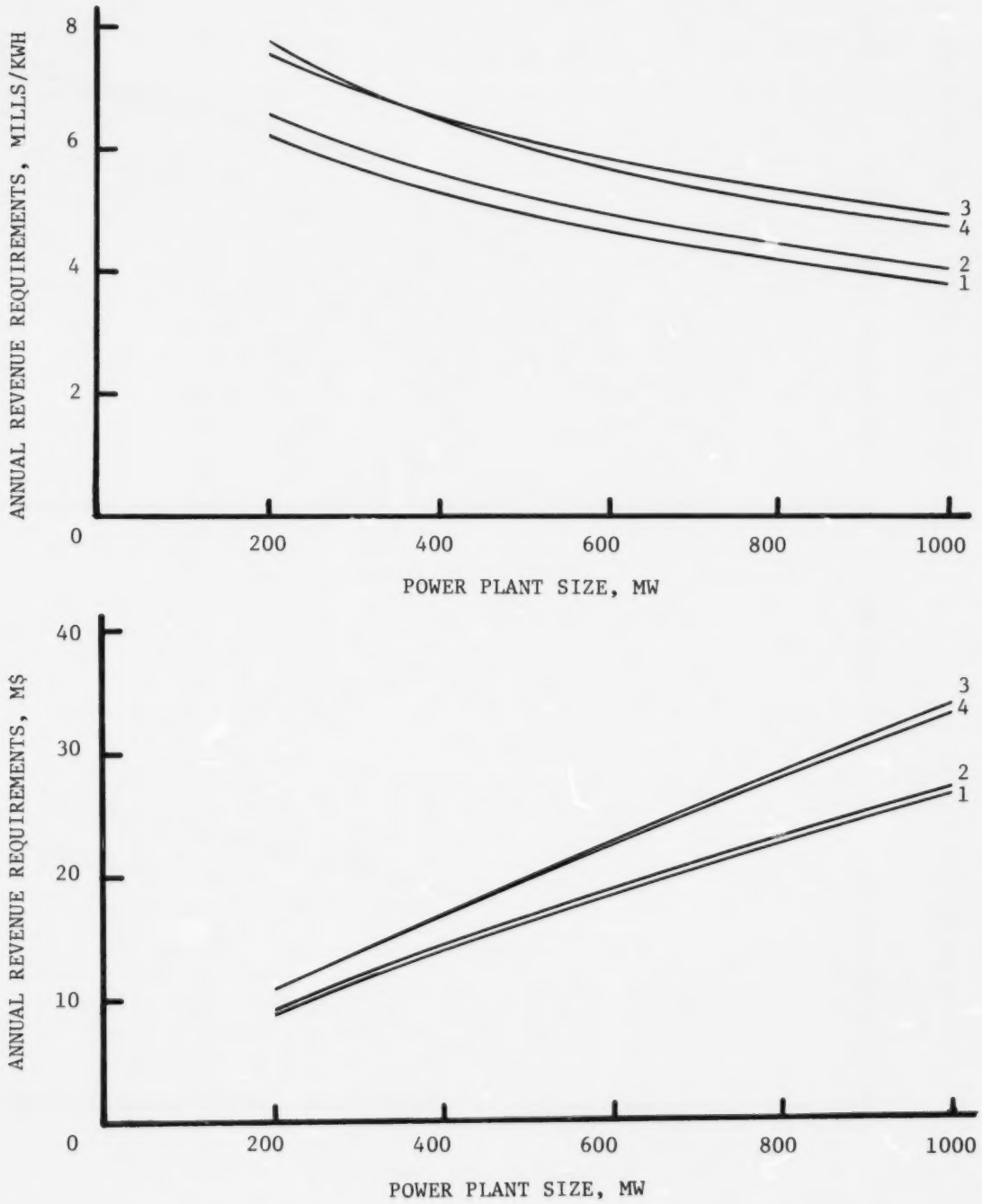

Figure 16. Effect of power plant size on annual revenue requirements. 1 - ACP, 2 - Wellman-Lord/sulfuric acid, 3 - Wellman-Lord/Resox, 4 - Wellman-Lord/Allied.

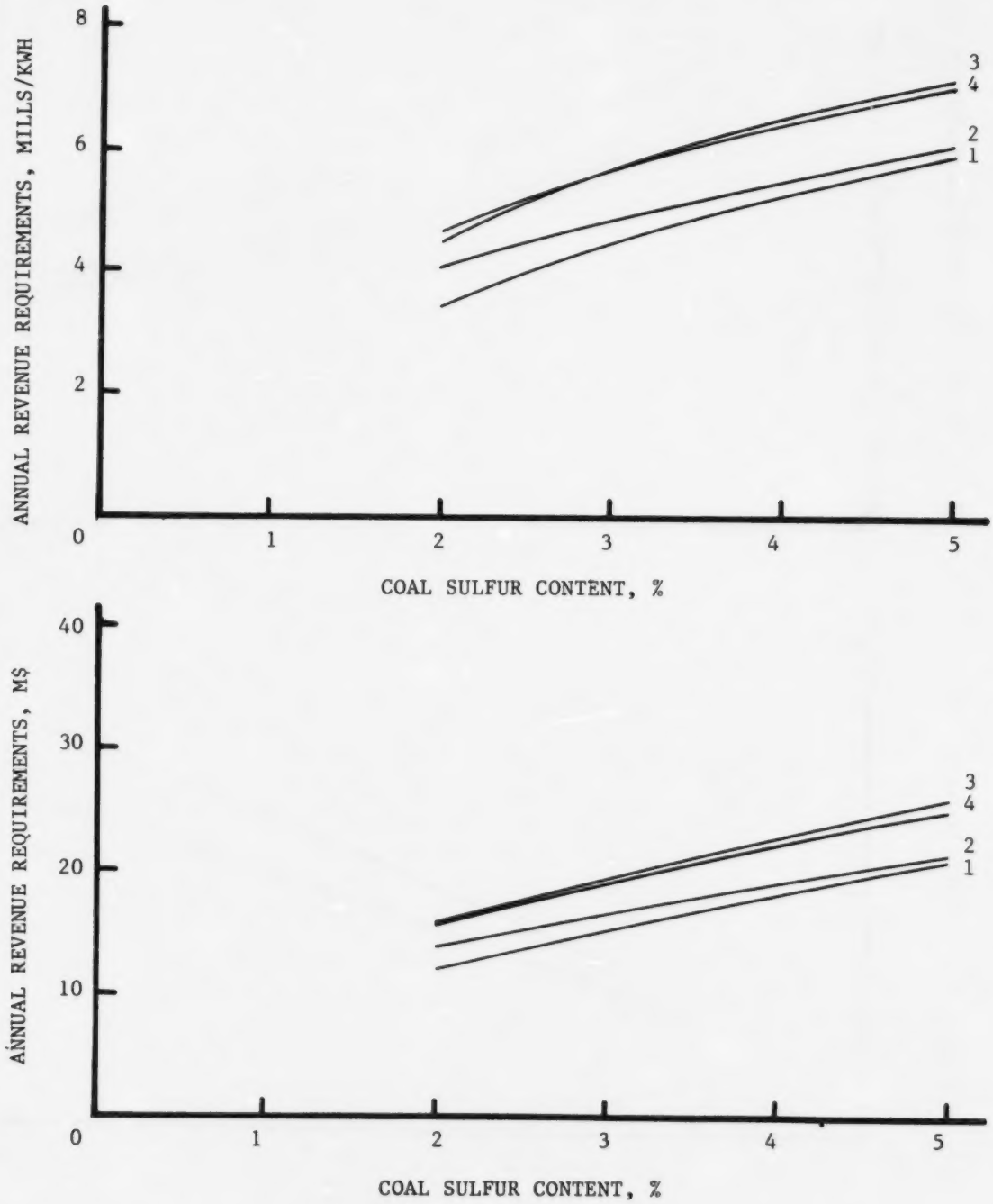

Figure 17. Effect of coal sulfur content on annual revenue requirements. 1 - ACP, 2 - Wellman-Lord/sulfuric acid, 3 - Wellman-Lord/Resox, 4 - Wellman-Lord/Allied.

For the wet-scrubbing fly ash removal case variation in the Wellman-Lord processes, annual revenue requirements are reduced about 3% from the base case. The results are shown in Table 37. Electricity requirements are increased about one-half, roughly 0.3 mill/kWh, indirect costs are decreased about the same amount because of the lower capital charges, maintenance costs decrease slightly, and there is a small ESP electricity credit. The capital charges are lower because of the ESP credit applied to capital investment.

Reduction of the Resox unit and Allied unit sulfur conversion rate to 90% of the base-case rate also has a minor effect on annual revenue requirements. Costs are increased about 5%, primarily because of increased raw material and utility requirements.

The annual revenue requirements for the case variations for oil-fired power plants, shown in Table 38, have the same relationships as the capital investments. The Wellman-Lord/sulfuric acid process has the lowest annual revenue requirements, followed by the ACP, the Wellman-Lord/Resox process and the Wellman-Lord/Allied process. As in the other existing power plant case variations, the ACP has the lowest direct costs but the highest indirect costs. Not only is there no ESP capital investment credit for the ACP, which increases ACP indirect costs, but chloride removal costs for the Wellman-Lord processes are eliminated, which decreases both direct and indirect costs for these processes. Oil-fired flue gas reheat is used, however, increasing the Wellman-Lord processes reheating costs about 15%. The overall effect is an improvement in the economics of the Wellman-Lord processes relative to the ACP, making the three sulfur-producing processes essentially equivalent in annual revenue requirements.

LIFETIME REVENUE REQUIREMENTS

Computer projections of the year-to-year operating cost and sales revenue analyses for all case variations for each of the processes are shown in the appendix. These projections are prepared on a regulated economics basis as discussed in the premises and correspond to the 30-year declining operating profile described in the premises. Annual capital charges are based on the undepreciated investment. Lifetime costs, both total and discounted at the regulated cost of money (11.6% for this study), and equivalent unit revenue requirements are shown. Summarized results of the lifetime revenue requirement projections are shown in Tables 39-42. The discounted lifetime revenue requirements are the year-by-year annual revenue requirements discounted to mid-1980 values at 11.6%. The levelized lifetime unit revenue requirements are obtained by dividing the discounted revenue requirements by the discounted number of units defining the cost.

TABLE 37. WELLMAN-LORD PROCESSES ANNUAL REVENUE REQUIREMENTS WITH WET-SCRUBBING FLY ASH REMOVAL

	Mills/kWh						
		Wellman-Lord/sulfuric acid		Wellman-Lord/Resox		Wellman-Lord/Allied	
	ACP base case	Base case	Wet fly ash removal	Base case	Wet fly ash removal	Base case	Wet fly ash removal
Raw materials							
Soda ash	0.32	0.19	0.19	0.19	0.19	0.19	0.19
Anthracite	-	-	-	0.57	0.57	-	-
Coal	0.36	-	-	-	-	0.21	0.21
Other	-	0.01	0.01	0.01	0.01	0.01	0.01
Total	0.68	0.20	0.20	0.77	0.77	0.41	0.41
Labor and supervision	0.19	0.19	0.17	0.17	0.17	0.17	0.17
Utilities							
Fuel oil	0.26	-	-	0.09	0.09	0.05	0.05
Steam	-	0.89	0.89	0.90	0.90	0.90	0.90
Electricity	0.56	0.64	0.81	0.63	0.88	0.64	0.89
Water	0.02	0.18	0.17	0.14	0.14	0.14	0.14
Heat credit	(0.11)	(0.03)	(0.03)	(0.11)	(0.11)	(0.03)	(0.03)
Total	0.73	1.68	1.84	1.65	1.90	1.70	1.95
Maintenance and analysis	0.67	0.63	0.56	0.66	0.59	0.68	0.60
Total direct costs	2.27	2.68	2.86	3.25	3.43	2.96	3.13
Indirect costs	2.95	3.19	2.86	3.32	2.99	3.29	3.05
Byproduct credit	(0.41)	(0.77)[a]	(0.77)[a]	(0.54)[a,b]	(0.54)[a,b]	(0.41)[a]	(0.41)[a]
Total	4.81	5.11	4.95	6.03	5.87	5.94	5.77

a. Includes 0.05 mill/kWh for Na_2SO_4.
b. Includes 0.12 mill/kWh for spent anthracite.

TABLE 38. ANNUAL REVENUE REQUIREMENT COST ELEMENTS

FOR OIL-FIRED POWER PLANTS

	Mills/kWh			
	ACP	Wellman-Lord/ sulfuric acid	Wellman-Lord/ Resox	Wellman-Lord/ Allied
Raw materials				
Soda ash	0.14	0.08	0.08	0.08
Anthracite	0.16	-	0.25	-
Coal	-	-	-	0.09
Other	-	0.02	0.02	0.02
Total	0.30	0.10	0.35	0.19
Labor and Supervision	0.18	0.16	0.16	0.16
Utilities				
Fuel oil	0.11	0.28	0.32	0.30
Steam	-	0.29	0.29	0.29
Electricity	0.37	0.44	0.44	0.44
Water	0.01	0.08	0.06	0.07
Heat credit	(0.05)	(0.01)	(0.05)	(0.01)
Total	0.44	1.08	1.06	1.08
Maintenance and analysis	0.55	0.39	0.41	0.43
Total direct costs	1.48	1.73	1.98	1.86
Indirect costs	2.49	2.04	2.12	2.20
Byproduct credit	(0.18)	(0.34)	(0.24)	(0.18)
Total	3.79	3.42	3.86	3.88

TABLE 39. AQUEOUS CARBONATE PROCESS LIFETIME REVENUE REQUIREMENTS

Case	Years remaining life	Actual lifetime revenue requirements					Discounted	Levelized			
		M$	$/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed	M$	$/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu-heat-input allowable emission											
200 MW, 3.5% sulfur	20	171,129,400	32.89	14.88	1.57	1,426.08	76,927,400	29.89	13.52	1.42	1,292.90
200 MW, 3.5% sulfur	30	224,602,800	20.11	8.81	0.96	868.87	79,534,700	18.27	8.00	0.87	789.03
500 MW, 3.5% sulfur	25	406,539,800	20.06	8.79	0.96	864.98	163,138,300	17.77	7.78	0.85	765.55
500 MW, 2.0% sulfur	30	310,832,400	11.38	4.88	0.54	1,068.15	110,193,000	10.35	4.43	0.49	970.86
• 500 MW, 3.5% sulfur	30	431,568,200	15.80	6.77	0.75	680.71	153,374,600	14.40	6.17	0.69	620.95
500 MW, 5.0% sulfur	30	526,826,800	19.28	8.26	0.92	540.34	187,635,600	17.62	7.55	0.84	493.91
1,000 MW, 3.5% sulfur	25	648,737,300	16.36	7.01	0.78	705.53	261,119,900	14.54	6.23	0.69	626.64
1,000 MW, 3.5% sulfur	30	675,306,500	12.78	5.30	0.61	551.72	204,904,900	11.70	4.85	0.56	504.94
90% SO_2 removal											
500 MW, 3.5% sulfur	30	456,945,400	16.73	7.17	0.80	633.33	162,492,700	15.26	6.54	0.73	577.85
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission											
500 MW, 2.5% sulfur	25	288,309,000	(4.10)	6.23	0.68	1,420.24	115,274,100	(3.62)	5.50	0.60	1,255.71

TABLE 40. WELLMAN-LORD/SULFURIC ACID PROCESS LIFETIME REVENUE REQUIREMENTS

Case	Years remaining life	Actual lifetime revenue requirements M$	$/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed	Discounted M$	Levelized $/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu-heat-input allowable emission											
200 MW, 3.5% sulfur	20	165,186,700	31.75	14.36	1.51	1,376.56	74,357,000	28.90	13.07	1.38	1,249.70
200 MW, 3.5% sulfur	30	236,603,300	21.18	9.28	1.01	915.29	83,943,100	19.28	8.45	0.92	832.77
500 MW, 3.5% sulfur	25	392,857,900	19.39	8.49	0.92	835.87	158,055,600	17.22	7.54	0.82	741.70
500 MW, 2.0% sulfur	30	362,698,400	13.28	5.69	0.63	1,246.39	129,034,000	12.12	5.19	0.58	1,136.86
• 500 MW, 3.5% sulfur	30	460,522,800	16.86	7.22	0.80	726.38	163,916,600	15.40	6.60	0.73	663.63
500 MW, 5.0% sulfur	30	544,696,200	19.94	8.54	0.95	558.66	194,008,800	18.22	7.81	0.87	510.68
1,000 MW, 3.5% sulfur	25	620,909,900	15.66	6.71	0.75	675.27	250,753,400	13.96	5.98	0.66	601.76
1,000 MW, 3.5% sulfur	30	723,198,500	13.69	5.67	0.65	590.85	258,361,200	12.55	5.20	0.60	541.52
90% SO_2 removal											
500 MW, 3.5% sulfur	30	482,738,200	17.67	7.57	0.84	669.08	171,861,100	16.14	6.92	0.77	611.17
Wet-scrubbing fly ash removal	30	435,767,700	15.95	6.84	0.76	687.33	155,818,800	14.63	6.27	0.70	630.85
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission											
500 MW, 2.5% sulfur	25	250,492,900	(3.56)	5.42	0.59	1,233.96	101,009,400	(3.17)	4.82	0.52	1,100.32

TABLE 41. WELLMAN-LORD/RESOX PROCESS LIFETIME REVENUE REQUIREMENTS

Case	Years remaining life	Actual lifetime revenue requirements					Discounted	Levelized			
		M$	$/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed	M$	$/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu-heat-input allowable emission											
200 MW, 3.5% sulfur	20	182,036,500	34.99	15.83	1.67	1,516.97	82,280,200	31.97	14.47	1.52	1,382.86
200 MW, 3.5% sulfur	30	266,401,200	23.85	10.45	1.14	1,030.57	95,088,900	21.84	9.57	1.04	943.34
500 MW, 3.5% sulfur	25	444,308,700	21.93	9.61	1.04	945.34	180,293,300	19.64	8.60	0.94	846.05
500 MW, 2.0% sulfur	30	395,304,800	14.47	6.20	0.69	1,358.44	141,244,100	13.26	5.68	0.63	1,244.44
* 500 MW, 3.5% sulfur	30	526,415,700	19.27	8.26	0.92	830.31	188,725,900	17.72	7.59	0.84	764.07
500 MW, 5.0% sulfur	30	642,505,900	23.52	10.08	1.12	658.98	230,942,600	21.69	9.29	1.03	607.90
1,000 MW, 3.5% sulfur	25	714,686,800	18.03	7.73	0.86	777.26	291,544,000	16.23	6.96	0.77	699.65
1,000 MW, 3.5% sulfur	30	842,995,900	15.96	6.61	0.76	688.72	303,674,300	14.75	6.11	0.70	636.50
90% SO_2 removal											
500 MW, 3.5% sulfur	30	556,883,100	20.38	8.74	0.97	771.84	199,798,800	18.76	8.04	0.89	710.52
Lower (90% of base case) sulfur conversion factor	30	550,313,300	20.14	8.63	95.92	868.00	197,462,000	18.54	7.95	0.88	799.44
Wet-scrubbing fly ash removal	30	501,928,800	18.37	7.87	0.87	791.69	180,704,800	16.97	7.27	0.81	731.60
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission											
500 MW, 2.5% sulfur	25	275,127,300	(3.91)	5.95	0.65	1,355.31	111,603,700	(3.50)	5.33	0.58	1,215.73

TABLE 42. WELLMAN-LORD/ALLIED PROCESS LIFETIME REVENUE REQUIREMENTS

Case	Years remaining life	Actual lifetime revenue requirements M$	$/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed	Discounted M$	Levelized $/ton (bbl) fuel burned	Mills/ kWh	$/MBtu heat input	$/ton S removed
Coal-Fired Power Unit											
1.2 lb SO_2/MBtu-heat-input allowable emission											
200 MW, 3.5% sulfur	20	187,731,200	36.08	16.32	1.72	1,564.43	84,730,400	32.93	14.90	1.57	1,424.04
200 MW, 3.5% sulfur	30	273,008,800	24.44	10.71	1.16	1,056.13	97,243,900	22.33	9.78	1.06	964.72
500 MW, 3.5% sulfur	25	443,161,400	21.87	9.58	1.04	942.90	179,486,900	19.55	8.56	0.93	842.27
500 MW, 2.0% sulfur	30	400,794,500	14.67	6.29	0.70	1,377.30	143,006,400	13.43	5.75	0.64	1,259.97
• 500 MW, 3.5% sulfur	30	523,730,600	19.17	8.22	0.91	826.07	187,407,000	17.60	7.54	0.84	758.73
500 MW, 5.0% sulfur	30	630,276,400	23.07	9.89	1.10	646.44	226,070,100	21.23	9.10	1.01	595.08
1,000 MW, 3.5% sulfur	25	699,001,900	17.63	7.56	0.84	760.20	284,651,200	15.85	6.79	0.75	683.11
1,000 MW, 3.5% sulfur	30	823,098,700	15.58	6.46	0.74	672.47	295,964,400	14.37	5.96	0.68	620.34
90% SO_2 removal											
500 MW, 3.5% sulfur	30	551,902,400	20.20	8.66	0.96	764.94	197,642,300	18.56	7.95	0.88	702.85
Lower (90% of base case) sulfur conversion factor	30	545,203,800	19.96	8.55	0.95	859.94	195,247,500	18.33	7.86	0.87	790.48
Wet-scrubbing fly ash removal	30	498,864,500	18.26	7.83	0.87	786.85	179,259,300	16.83	7.21	0.80	725.75
Oil-Fired Power Unit											
0.8 lb SO_2/MBtu heat input allowable emission											
500 MW, 2.5% sulfur	25	279,994,100	(3.98)	6.05	0.66	1,379.28	113,361,200	(3.56)	5.41	0.59	1,234.87

VARIATIONS IN ECONOMIC FACTORS

The cost elements composing annual revenue requirements are subject to numerous technical and economic influences that can alter not only the operating costs of the processes but their economic relationships to other processes. The major cost elements of the four processes are soda ash; reducing coal; the conversion cost elements of operating labor and supervision, electricity, fuel oil, steam, and maintenance; capital charges; and byproduct credit. The importance of each varies with the particular process and with the conditions of operation. Fuel oil, for example, is an important cost element only for the ACP; also, no reducing coal is used in the Wellman-Lord/sulfuric acid process. Some, such as operating labor and supervision, are primarily size-dependent. Others, such as raw materials, are directly related to the quantity of sulfur removed. Capital charges, based on capital investment, vary according to the age--and hence undepreciated capital--of the FGD system. For these first-year annual revenue requirements capital charges constitute about one-half of the annual revenue requirements, a proportion diminishing over the life of the FGD system.

To illustrate the effects of various cost elements, the annual revenue requirements for cost variations in specific cost elements are shown in Tables 43 and 44. The costs, as a percentage of annual revenue requirements, are shown in Table 45.

Soda ash costs are 5% or less of the Wellman-Lord processes annual revenue requirements and 10% or less of the ACP annual revenue requirements. The ACP is thus more sensitive to soda ash price variations because of its higher consumption. Similarly, the Wellman-Lord/Resox process is more sensitive to reducing coal costs, which constitute about 6% to 12% of its annual revenue requirements, as compared with a maximum of 8% for the ACP and Wellman-Lord/Allied process.

Operating labor and supervision costs range from 4% to 9% of annual revenue requirements. They are highest, as a percentage of the total, for the ACP and essentially equivalent for the three Wellman-Lord process variations. Fuel oil costs are 3.5% to 6.8% of the ACP annual revenue requirements, the percentage increasing with both power plant size and coal sulfur content. Steam costs are 12% to 21% of the annual revenue requirements for the three Wellman-Lord processes. Electricity costs are 9% to 13% of annual revenue requirements. Maintenance costs are the largest element of conversion costs, ranging from 13% to 23% of the annual revenue requirements. A higher percentage of the ACP annual revenue requirements is in maintenance costs compared with the Wellman-Lord processes (although the amount is lower than the Wellman-Lord processes) and the ACP is thus slightly more sensitive to variations in maintenance costs.

Capital charges are the largest cost element for all of the processes. The effect of variations in capital investment declines, however, with the decline in capital charges with age as the equipment is depreciated.

TABLE 43. EFFECT OF COST VARIATIONS AT DIFFERENT POWER UNIT SIZES ON ANNUAL REVENUE REQUIREMENTS

Cost, % of base value	Annual revenue requirements, M$											
	ACP			Wellman-Lord/sulfuric acid			Wellman-Lord/Resox			Wellman-Lord/Allied		
	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW	200 MW	500 MW	1000 MW
Soda ash												
75%	8.61	16.54	25.98	8.67	17.73	28.05	10.49	20.94	33.99	10.64	20.63	32.85
Base value	8.72	16.82	26.52	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
125%	8.84	17.10	27.05	9.21	18.05	28.68	10.62	21.27	34.62	10.77	20.95	33.48
150%	8.95	17.38	27.59	9.27	18.22	28.99	10.69	21.43	34.93	10.83	21.11	33.80
Reducing coal												
75%	8.59	16.50	25.91	-	-	-	10.56	20.60	34.30	10.63	20.69	32.81
Base value	8.72	16.82	26.52	-	-	-	10.35	21.11	33.32	10.70	20.79	33.17
125%	8.85	17.14	27.13	-	-	-	10.76	21.61	35.28	10.78	21.05	33.52
150%	8.98	17.45	27.74	-	-	-	10.97	22.12	36.26	10.85	21.23	33.88
Operating labor and supervision												
Base value	8.72	16.82	26.52	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
200%	9.49	17.87	27.89	9.75	18.85	29.72	11.17	22.07	35.66	11.31	21.75	34.53
300%	10.25	18.92	29.27	10.36	19.81	31.08	11.77	23.03	37.02	11.92	22.71	35.89
Fuel oil												
Base value	8.72	16.82	26.52	-	-	-	-	-	-	-	-	-
150%	8.91	17.28	27.41	-	-	-	-	-	-	-	-	-
200%	9.10	17.74	28.30	-	-	-	-	-	-	-	-	-
250%	9.29	18.20	29.19	-	-	-	-	-	-	-	-	-
Steam												
75%	-	-	-	8.82	17.10	26.84	10.23	20.31	32.77	10.38	19.99	31.63
Base	-	-	-	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
125%	-	-	-	9.46	18.68	29.88	10.88	21.90	35.84	11.03	21.58	34.70
150%	-	-	-	9.78	19.47	31.41	11.21	22.69	37.37	11.35	22.38	36.24
Electricity												
75%	8.50	16.32	25.58	8.89	17.32	27.31	10.31	20.55	33.26	10.45	20.23	32.11
Base value	8.72	16.82	26.52	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
125%	8.95	17.32	27.45	9.39	18.46	29.42	10.81	21.67	35.35	10.95	21.36	34.22
150%	9.17	18.98	28.39	9.64	19.03	30.47	11.05	22.23	36.39	11.20	21.93	35.28
Maintenance												
75%	8.26	15.99	25.40	8.69	17.11	27.32	10.08	20.28	33.21	10.20	19.94	32.07
Base value	8.72	16.82	26.52	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
125%	9.19	17.65	27.63	9.59	18.68	29.41	11.03	21.92	35.40	11.21	21.63	34.26
150%	9.66	18.48	28.75	10.04	19.46	30.45	11.51	22.75	36.49	11.71	22.48	35.36
Capital charges												
75%	7.62	14.66	23.15	7.93	15.53	24.70	9.28	18.63	30.46	9.35	18.25	29.30
Base value	8.72	16.82	26.52	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
125%	9.83	18.98	29.88	10.35	20.25	32.02	11.84	23.59	38.15	12.06	23.33	37.03
150%	10.94	21.13	33.24	11.57	22.62	35.68	13.12	26.07	42.00	13.41	25.87	40.90
Sulfur or sulfuric acid price												
50%	8.99	17.47	27.78	9.61	19.20	30.54	10.80	21.70	35.44	10.93	21.35	34.24
Base value	8.72	16.82	26.52	9.14	17.89	28.36	10.56	21.11	34.30	10.70	20.79	33.17
150%	8.46	16.17	25.26	8.68	16.82	26.19	10.32	20.52	33.16	10.47	20.23	32.05
200%	8.19	15.52	24.00	8.22	15.82	24.01	10.08	19.93	32.02	10.25	19.67	30.98

TABLE 44. EFFECT OF COST VARIATIONS AT DIFFERENT COAL SULFUR CONTENTS ON ANNUAL REVENUE REQUIREMENTS

Cost, % of base value	Annual revenue requirements, M$											
	ACP			Wellman-Lord/sulfuric acid			Wellman-Lord/Resox			Wellman-Lord/Allied		
	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S	2.0% S	3.5% S	5.0% S
Soda ash												
75%	11.90	16.54	20.28	14.00	17.73	20.97	15.55	20.94	25.79	15.65	20.63	25.02
Base value	12.03	16.82	20.71	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
125%	12.15	17.10	21.13	14.15	18.05	21.47	15.70	21.27	26.29	15.80	20.95	25.52
150%	12.28	17.38	21.56	14.22	18.22	21.72	15.78	21.43	26.54	15.87	21.11	25.77
Reducing coal												
75%	11.88	16.50	25.91	-	-	-	15.40	20.60	25.27	15.64	20.69	24.98
Base value	12.03	16.82	26.52	-	-	-	15.63	21.11	26.04	15.72	20.79	25.27
125%	12.17	17.14	27.13	-	-	-	15.86	21.61	26.82	15.80	21.05	25.55
150%	12.32	17.45	27.74	-	-	-	16.09	22.12	27.60	15.89	21.23	25.84
Operating labor and supervision												
Base value	12.03	16.82	20.71	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
200%	13.00	17.87	21.82	14.93	18.85	22.25	16.49	22.07	27.08	16.57	21.75	26.30
300%	13.97	18.92	22.93	15.79	19.81	23.29	17.35	23.03	28.11	17.42	22.71	27.33
Fuel oil												
Base value	12.03	16.82	20.71	-	-	-	-	-	-	-	-	-
150% (75%)	12.24	17.28	21.42	-	-	-	-	-	-	-	-	-
200% (125%)	12.45	17.74	22.12	-	-	-	-	-	-	-	-	-
250% (150%)	12.51	18.20	22.83	-	-	-	-	-	-	-	-	-
Steam												
75%	-	-	-	13.59	17.10	20.12	15.15	20.31	24.94	15.25	19.99	24.16
Base value	-	-	-	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
125%	-	-	-	14.55	18.68	22.32	16.11	21.90	27.15	16.19	21.58	26.38
150%	-	-	-	15.02	19.47	23.41	16.59	22.69	28.26	16.67	22.38	27.49
Electricity												
75%	11.65	16.32	20.07	13.63	17.32	20.53	15.19	20.55	25.37	15.28	20.23	24.58
Base value	12.03	16.82	20.71	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
125%	12.40	17.32	21.34	14.56	18.46	21.91	16.07	21.67	26.72	16.16	21.36	25.96
150%	12.77	18.98	21.97	15.00	19.03	22.60	16.52	22.23	27.40	16.60	21.93	26.65
Maintenance												
75%	11.43	15.99	19.70	13.46	17.11	20.29	15.00	20.28	25.06	15.07	19.94	24.27
Base value	12.03	16.82	20.71	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
125%	12.61	17.65	21.71	14.68	18.68	22.15	16.26	21.92	27.03	16.37	21.63	26.26
150%	13.20	18.48	22.72	15.29	19.46	23.09	16.90	22.75	28.01	17.02	22.48	27.26
Capital charges												
75%	10.45	14.66	18.13	12.20	15.53	18.45	13.69	18.63	23.11	13.71	18.25	22.30
Base value	12.03	16.82	20.71	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
125%	13.60	18.98	23.28	15.94	20.25	23.99	17.67	23.59	28.98	17.73	23.33	28.24
150%	15.18	21.13	25.86	17.81	22.62	26.76	19.51	26.07	31.91	19.74	25.87	31.21
Sulfur or sulfuric acid price												
50%	12.33	17.47	21.71	14.59	19.20	22.95	15.90	21.70	26.86	15.98	21.35	26.12
Base value	12.03	16.82	20.71	14.07	17.89	21.22	15.63	21.11	26.04	15.72	20.79	25.27
150%	11.73	16.17	19.71	13.55	16.82	19.49	15.35	20.52	25.04	15.46	20.23	24.41
200%	11.43	15.52	18.70	13.03	15.82	17.76	15.09	19.93	24.14	15.21	19.67	23.55

TABLE 45. IMPORTANCE OF ANNUAL REVENUE REQUIREMENT COST ELEMENTS FOR DIFFERENT POWER PLANT SIZE AND COAL SULFUR CONTENTS

Cost element	Percentage of annual revenue requirements			
	ACP	Wellman-Lord/ sulfuric acid	Wellman-Lord/ Resox	Wellman-Lord/ Allied
Soda ash				
200 MW	5.2	2.9	2.5	2.5
500 MW	6.6	3.6	3.0	3.1
1000 MW	8.1	4.4	3.7	4.0
2% sulfur	4.8	2.1	1.9	1.9
5% sulfur	9.4	4.7	3.8	3.8
Reducing coal				
200 MW	5.9	-	7.7	2.8
500 MW	7.5	-	9.4	3.5
1000 MW	9.2	-	11.2	4.2
2% sulfur	4.2	-	5.9	2.1
5% sulfur	8.2	-	12.0	6.8
Operating labor and supervision				
200 MW	8.7	6.6	5.7	5.6
500 MW	6.2	5.3	4.5	4.6
1000 MW	5.1	4.7	3.9	4.1
2% sulfur	8.0	6.0	5.4	5.4
5% sulfur	5.3	4.8	3.9	4.0
Fuel oil				
200 MW	4.3	-	-	-
500 MW	5.4	-	-	-
1000 MW	6.6	-	-	-
2% sulfur	3.5	-	-	-
5% sulfur	6.8	-	-	-
Steam				
200 MW	-	13.9	12.2	12.0
500 MW	-	17.4	14.9	15.1
1000 MW	-	21.2	17.7	18.3
2% sulfur	-	13.4	12.1	12.0
5% sulfur	-	20.4	16.8	17.4
Electricity				
200 MW	10.0	10.9	9.3	9.3
500 MW	11.7	12.5	10.5	10.8
1000 MW	13.9	14.7	12.0	12.6
2% sulfur	12.0	12.5	11.2	11.2
5% sulfur	12.1	12.8	10.3	10.8
Maintenance				
200 MW	22.6	19.6	17.9	18.7
500 MW	20.8	17.4	15.4	16.1
1000 MW	13.3	14.5	12.6	13.1
2% sulfur	20.[illegible]	17.2	16.0	16.5
5% sulfur	20.5	17.4	14.9	15.6
Capital charges				
200 MW	50.8	53.1	48.5	50.6
500 MW	51.3	52.8	47.0	48.9
1000 MW	50.7	51.6	44.8	46.6
2% sulfur	52.4	53.1	49.6	51.2
5% sulfur	49.8	52.3	45.0	47.0
Byproduct credit				
200 MW	6.1	10.1	4.6	4.3
500 MW	7.8	12.6	5.6	5.4
1000 MW	9.5	15.4	6.7	6.5
2% sulfur	5.0	7.4	3.5	3.3
5% sulfur	9.7	16.3	7.0	6.8

Basis: New power plants, 3.5% sulfur coal for size variations, 500-MW size for sulfur variations. Percentages include overheads and marketing expense for operating labor and supervision, maintenance, and byproduct credit.

Byproduct sales credit is a larger element as a percentage of total annual revenue requirements for the Wellman-Lord/sulfuric acid process than for the other processes because of the higher credit for sulfuric acid, compared with sulfur, combined with the relatively low operating cost of the process. Byproduct sales credit is a smaller cost element for the Wellman-Lord/Resox and Wellman-Lord/Allied processes because of the lower sales credit for sulfur combined with the relatively high operating costs of the processes. The Wellman-Lord/sulfuric acid process and the ACP are thus more sensitive, in terms of percentage change, to variations in byproduct sales credit than the other processes.

In general, no single large cost element unique to a single process occurs in the annual revenue requirements of the four processes. The ACP is slightly more sensitive to soda ash cost and the Wellman-Lord/Resox process is more sensitive to reducing coal (anthracite) cost but the effects of large cost variations are not severe. Electricity, operating labor, and maintenance costs are similar for all four processes. Fuel oil costs for the ACP could become an important cost factor with large increases in oil costs. A tripling of the 0.40 $/gal price used in this study, for example, would make fuel oil costs for the ACP roughly equivalent to the steam costs for the three Wellman-Lord processes. The effect of changes in capital charges would be about the same for all four processes. The likelihood of large changes in capital investment, however, can be considered greater for less developed processes. Thus, the Wellman-Lord/sulfuric acid process should be less susceptable to annual revenue requirement variations due to capital charges than the other processes. The relatively expensive reduction and regeneration portions of the ACP and the Resox and Allied reduction processes, on the other hand, have not been commercially demonstrated. Byproduct credits for the Wellman-Lord/sulfuric acid process are larger, making its annual revenue requirements more sensitive to byproduct prices.

ENERGY REQUIREMENTS

The energy requirements of the four processes are shown in Table 46. The steam and electricity requirements are expressed in terms of the power plant fuel consumed in producing them. The energy requirements are for utilities and do not include energy in the reducing coal nor the energy consumed in production and transportation of raw materials. The gross energy requirement (the amount of steam, electricity, and fuel oil required by the process) is reduced by heat credits for steam produced and used in the processes and, for the Wellman-Lord/Resox process, spent anthracite sent to the power plant.

The gross energy requirements for the ACP are about one-third those of the three Wellman-Lord processes, primarily because the ACP does not require process steam and reheat steam. Process steam constitutes about one-half and reheat steam an additional one-fifth of the gross energy requirements of the three Wellman-Lord processes. About 35% of the ACP gross energy requirements are met by fuel oil, however, compared with about 5% for the Wellman-Lord/Resox process and 2% for the Wellman-

TABLE 46. ENERGY REQUIREMENTS

Process	Equivalent MBtu/year							Percent of power unit input energy
	Reheat	Electricity	Process steam	Fuel oil	Gross total	Heat credit	Net total	
ACP	-	611,300	-	327,500	938,800	(223,300)	715,500	2.27
Wellman-Lord/sulfuric acid	466,100	696,300	1,263,500	-	2,425,900	(53,800)	2,372,100	7.53
Wellman-Lord/Resox	462,700	688,800	1,281,000	114,300	2,546,800	(565,500)[a]	1,981,300	6.29
Wellman-Lord/Allied	460,600	698,100	1,284,800	61,500	2,505,000	(65,200)	2,439,800	7.75

Basis: Base-case 500-MW power plant. Equivalent energy based on a 90% efficiency for steam generation, 9,000 Btu/kWh for electricity generation.

a. Includes 359,100 MBtu/year for spent anthracite sent to power plant.

Lord/Allied process. The three Wellman-Lord processes are very similar in gross energy requirement, the major difference being the amount of fuel oil required. The net energy requirement for the Wellman-Lord/Resox process is reduced substantially by the heat credit for spent anthracite.

CONCLUSIONS

The ESP credit and chloride removal costs are the major factors in the capital investment relationships of the ACP and the Wellman-Lord processes. The capital cost relativity of the processes depends on both design and need for particulate and chloride control facilities in addition to the FGD equipment.

Combining fly ash removal and chloride removal into a single wet-scrubbing operation in the Wellman-Lord process results in only a slight increase in capital investment for the scrubber system and, therefore, a substantial saving in particulate control capital investment.

Among the three Wellman-Lord processes, the cost differences are the result of the costs of sulfuric acid, Resox, and Allied units. The changes necessary to accommodate these chemical processing units have little effect on the total process capital investment.

The capital investments of the Resox and Allied units do not differ significantly. The Allied unit coal handling and sulfur collection and handling facilities are more expensive than these areas of the Resox unit. The Resox reactor area is more expensive than the Allied reactor area, however. If more complicated coal handling equipment were used with the Resox unit (to use a coal other than graded anthracite, for example) its cost could be increased. The same would be true if more complicated sulfur collection and cleaning equipment were required.

The annual revenue requirements follow the same general relationships among the processes as the capital investment requirements. This relationship is largely the result of indirect costs related to capital investment. The ACP is substantially lower in direct costs than the three Wellman-Lord processes, primarily because it does not require steam. The ACP has a substantial fuel oil requirement, however; a cost potentially more sensitive to inflation than the coal-based utility requirements of the Wellman-Lord processes. Large fuel oil cost increases (from the 0.40 $/gal used in this series of evaluations) would greatly decrease the utility-cost advantage of the ACP.

There is no significant difference in annual revenue requirements for the Wellman-Lord process section of the three versions of the Wellman-Lord process. The cost differences are the result of end plant costs. The Wellman-Lord/sulfuric acid process has the lowest costs because of lower raw material, fuel oil, and indirect costs. The Wellman-Lord/Resox process has slightly higher annual revenue requirements than the Wellman-Lord/Allied process because of higher reducing coal costs. It also has

a higher heat credit, higher byproduct credit, and lower indirect costs which partially offset the reducing coal costs. The Wellman-Lord/Resox process is also probably more sensitive to cost variations due to location because of the geographically limited sources of anthracite.

Increasing power plant size results in a considerable economy of scale for all of the processes, primarily because of lower labor and supervision, maintenance, and indirect costs per unit of output at the larger power plant sizes. The ACP annual revenue requirements increase more rapidly with increasing coal sulfur content than the other processes as a result of the higher percentage of its costs directly related to the quantity of sulfur removed. A similar, less extreme effect is seen for the Wellman-Lord/Resox process because of the higher raw material costs.

Energy requirements for the ACP are much lower than those of the Wellman-Lord processes because it does not require process and reheat steam. The gross energy requirements of the three Wellman-Lord processes are similar. The Wellman-Lord/Resox process has lower net energy requirements because of a substantial heat credit for spent anthracite.

Considering stage of development as a factor in economic comparison, the ACP is probably more susceptible to cost changes and the Wellman-Lord/sulfuric acid process the least. The ACP regeneration system, a large cost element in the process, has not been demonstrated in utility FGD applications. The Allied process and the Resox process are in an early stage of development and may also be considered more susceptible to cost variations than proven technology such as the Wellman-Lord, sulfuric acid, and Claus processes. They represent a smaller portion of the overall FGD costs than the ACP regeneration area, however. Some cost advantages of the ACP such as lower energy requirements are unlikely to be greatly affected by continuing development.

COMPARISON WITH PREVIOUS STUDIES

In the previous studies of this series (Tomlinson et al., 1979; Anderson et al., 1980) five other processes were evaluated using the same premises. Three, the limestone, lime, and double-alkali processes, produce a waste slurry that is disposed of in a pond. In the limestone process the flue gas is scrubbed with a slurry of ground limestone, forming calcium-sulfur salts that are discarded by pumping a purge stream to a disposal pond. The lime process is similar except that a slurry of lime is used as the scrubbing medium. In the double-alkali process a solution of sodium sulfite is the scrubbing medium. The spent solution is regenerated by adding lime, producing calcium-sulfur salts that are discarded in a disposal pond.

A slurry of magnesium oxide is used as the scrubbing medium in the magnesia process. The spent slurry is dewatered, dried, and thermally decomposed to regenerate the magnesium oxide and produce SO_2 which is converted to sulfuric acid in a conventional acid plant.

The citrate process is a wet scrubbing process using a sodium citrate solution as the absorbent. The absorbent is regenerated and the SO_x compounds reduced to elemental sulfur by liquid-phase reduction using H_2S. The H_2S is produced by reducing some of the product sulfur using natural gas.

The base-case costs for each of the nine processes are shown below. Except for the ACP the costs are more product-controlled than process-controlled, falling into separate groupings of waste-, acid-, and sulfur-producing processes in both capital investment and annual revenue requirements. The differences in cost between the waste-producing and acid-producing processes are essentially the costs for absorbent regeneration; ponding costs and acid plant costs do not differ greatly and raw material costs do not differ sufficiently to produce large cost differences. The higher costs for sulfur-producing processes are the result of the added costs for reduction of sulfur oxides. Here coal reduction holds a strong advantage over other fossil reducing agents. In the citrate process, 16% of the annual revenue requirements (1.06 mills/kWh of 6.44 mills/kWh) are for natural gas to produce H_2S.

	Mid-1979 capital investment, $/kW	Mid-1980 annual revenue requirement, mills/kWh
Waste Producing Processes		
Limestone	98	4.02
Lime	90	4.25
Double alkali	101	4.19
Sulfuric Acid Processes		
Magnesia	132	5.08
Wellman-Lord/sulfuric acid	131	5.11
Sulfur Processes		
ACP	119	4.81
Wellman-Lord/Resox	138	6.03
Wellman-Lord/Allied	141	5.94
Citrate	143	6.44

The lower costs for the ACP compared with the other sulfur-producing processes are largely the result of the combination of fly ash and SO_x particulate matter removal. For the existing plant case variation, which mainly differs from the base case in having no ESP credit, the ACP capital investment is 136 $/kW and the annual revenue requirements are 5.42 mills/kWh.

RECOMMENDATIONS

The nine processes evaluated in this series of three studies represent processes of diverse types and widely differing stages of development. Development and testing of all nine processes is continuing. As has been demonstrated by comparisons of earlier TVA economic studies of the same processes with the results of this series, increased design and operating information has a profound effect on the economics, both absolute and comparative, of FGD processes. The same effects are seen from economic and environmental regulation changes. Accurate economic assessments thus require periodic and thorough reassessment of both technical and economic data and incorporation of the latest regulatory restrictions. There is thus a need for periodic economic reevaluation of FGD processes as well as evaluation of emerging processes. This is particularly true of the magnesia, ACP, Resox, and Allied processes, all of which should produce much more extensive information upon which to base economic evaluations in the near future. Well-developed, waste-producing processes such as the limestone and double-alkali processes should also be reassessed not only in respect to technical changes, but also in view of changing cost patterns in disposal methods. Energy requirements, both in quantity and type, have also been found to have increasingly important influences on FGD economics. Assessment of energy consumption patterns, including types, quantities, and the economic results of alternate types, should continue to be emphasized in FGD economic studies.

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APPENDIX A

TOTAL CAPITAL INVESTMENT, AVERAGE ANNUAL REVENUE REQUIREMENTS, AND LIFETIME REVENUE REQUIREMENTS TABLES - ALL PROCESSES AND CASE VARIATIONS

TABLE A-1. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	242,000	1.4
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	2,267,000	12.7
SO_2 absorption and removal (two spray dryers, two ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	4,685,000	26.2
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	4,014,000	22.4
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	1,185,000	6.6
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	2,350,000	13.1
Sulfur production (Claus plant with tail gas incinerator)	1,693,000	9.5
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	379,000	2.1
Subtotal	16,815,000	94.0
Services, utilities, and miscellaneous	1,009,000	5.6
Total process area excluding pond construction	17,824,000	99.6
Incremental ash pond cost	65,000	0.4
Total direct investment	17,889,000	100.0
Indirect Investment		
Engineering design and supervision	1,421,000	7.9
Architect and engineering contractor	353,000	2.0
Construction expense	2,744,000	15.4
Contractor fees	859,000	4.8
Total indirect investment	5,377,000	30.1
Contingency	4,653,000	26.0
Total fixed investment	27,919,000	156.1
Other Capital Charges		
Allowance for startup and modifications	2,785,000	15.6
Interest during construction	3,350,000	18.7
Total depreciable investment	34,054,000	190.4
Land	23,000	0.1
Working capital	764,000	4.3
Total capital investment	34,841,000	194.8

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-2. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW, existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	4,550 tons	103.00/ton	468,700	4.69
Coal	21,350 tons	25.00/ton	533,800	5.33
Catalyst			6,300	0.06
Total raw materials cost			1,008,800	10.08
Conversion costs				
Operating labor and supervision	37,770 man-hr	12.50/man-hr	472,100	4.72
Utilities				
Fuel oil	960,000 gal	0.40/gal	384,000	3.84
Process water	73,800 kgal	0.12/kgal	8,900	0.09
Boiler feedwater	28,700 kgal	0.92/kgal	26,400	0.26
Electricity	29,282,000 kWh	0.031/kWh	907,700	9.07
Heat credit	84,900 MBtu	2.00/MBtu	(169,800)	(1.70)
Maintenance				
Labor and material			1,427,900	14.26
Analyses	4,610 man-hr	17.00/man-hr	78,400	0.78
Total conversion costs			3,135,600	31.32
Total direct costs			4,144,400	41.40
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			2,383,800	23.81
Average cost of capital and taxes at 8.6% of total capital investment			2,996,300	29.93
Overheads				
Plant, 50% of conversion costs less utilities			989,200	9.88
Administrative, 10% of operating labor			47,200	0.47
Marketing, 10% of sales revenue			61,200	0.62
Total indirect costs			6,477,700	64.71
Gross average annual revenue requirements			10,622,100	105.76
Byproduct Sales Revenue				
Elemental sulfur	15,300 tons	40.00/ton	(612,000)	(5.76)
Net average annual revenue requirements			10,010,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	7.15	15.80	0.75	682

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 20 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
- Sulfur removed, 14,680 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $17,889,000; total depreciable investment, $34,054,000; and total capital investment, $34,841,000.
- All tons shown are 2,000 lb.

TABLE A-3

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 200 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 34841000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11	5000	9500000	452400	10500	10900	36.00	12963600	392400	12571200	12571200
12	5000	9500000	452400	10500	10900	36.00	12670700	392400	12278300	24849500
13	5000	9500000	452400	10500	10900	36.00	12377800	392400	11985400	36834900
14	5000	9500000	452400	10500	10900	36.00	12085000	392400	11692600	48527500
15	5000	9500000	452400	10500	10900	36.00	11792100	392400	11399700	59927200
16	3500	6650000	316700	7300	7700	36.00	10568300	277200	10291100	70218300
17	3500	6650000	316700	7300	7700	36.00	10275500	277200	9998300	80216600
18	3500	6650000	316700	7300	7700	36.00	9982600	277200	9705400	89922000
19	3500	6650000	316700	7300	7700	36.00	9689700	277200	9412500	99334500
20	3500	6650000	316700	7300	7700	36.00	9396900	277200	9119700	108456200
21	1500	2850000	135700	3100	3300	36.00	7704200	118800	7585400	116039600
22	1500	2850000	135700	3100	3300	36.00	7411300	118800	7292500	123332100
23	1500	2850000	135700	3100	3300	36.00	7118500	118800	6999700	130331800
24	1500	2850000	135700	3100	3300	36.00	6825600	118800	6706800	137038600
25	1500	2850000	135700	3100	3300	36.00	6532800	118800	6414000	143452600
26	1500	2850000	135700	3100	3300	36.00	6239900	118800	6121100	149573700
27	1500	2850000	135700	3100	3300	36.00	5947000	118800	5828200	155401900
28	1500	2850000	135700	3100	3300	36.00	5654200	118800	5535400	160937300
29	1500	2850000	135700	3100	3300	36.00	5361300	118800	5242500	166179800
30	1500	2850000	135700	3100	3300	36.00	5068400	118800	4949600	171129400
TOT	57500	109250000	5202500	120000	126000		175665400	4536000	171129400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	33.77	0.88	32.89
MILLS PER KILOWATT-HOUR	15.28	0.40	14.88
CENTS PER MILLION BTU HEAT INPUT	160.79	4.15	156.64
DOLLARS PER TON OF SULFUR REMOVED	1463.88	37.80	1426.08

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 79166800 2239400 76927400

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	30.76	0.87	29.89
MILLS PER KILOWATT-HOUR	13.92	0.40	13.52
CENTS PER MILLION BTU HEAT INPUT	146.51	4.15	142.36
DOLLARS PER TON OF SULFUR REMOVED	1330.53	37.63	1292.90

TABLE A-4. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	237,000	1.5
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	2,217,000	14.3
Fly ash collection (two cyclone dust collectors)	209,000	1.4
SO_2 absorption and removal (two spray dryers, two ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	4,578,000	29.5
ESP credit	(2,110,000)	(13.6)
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	3,925,000	25.4
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	1,160,000	7.5
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	2,299,000	14.9
Sulfur production (Claus plant with tail gas incinerator)	1,656,000	10.7
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	370,000	2.4
Subtotal	14,541,000	94.0
Services, utilities, and miscellaneous	872,000	5.6
Total process area excluding pond construction	15,413,000	99.6
Incremental ash pond cost	63,000	0.4
Total direct investment	15,476,000	100.0
Indirect Investment		
Engineering design and supervision	1,418,000	9.2
Architect and engineering contractor	353,000	2.3
Construction expense	2,433,000	15.7
Contractor fees	770,000	5.0
Total indirect investment	4,974,000	32.2
Contingency	4,090,000	26.4
Total fixed investment	24,540,000	158.6
Other Capital Charges		
Allowance for startup and modifications	2,448,000	15.8
Interest during construction	2,945,000	19.0
Total depreciable investment	29,933,000	193.4
Land	23,000	0.1
Working capital	714,000	4.6
Total capital investment	30,670,000	198.1

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-5. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	4,410 tons	103.00/ton	454,200	5.21
Coal	20,680 tons	25.00/ton	517,000	5.93
Catalyst			6,100	0.07
Total raw materials cost			977,300	11.21
Conversion costs				
Operating labor and supervision	37,770 man-hr	12.50/man-hr	472,100	5.41
Utilities				
Fuel oil	930,000 gal	0.40/gal	372,000	4.26
Process water	71,500 kgal	0.12/kgal	8,600	0.10
Boiler feedwater	27,800 kgal	0.92/kgal	25,600	0.29
Electricity	28,379,000 kWh	0.031/kWh	879,700	10.08
Heat credit	82,200 MBtu	2.00/MBtu	(164,400)	(1.88)
Maintenance				
Labor and material			1,234,900	14.15
Analyses	4,610 man-hr	17.00/man-hr	78,400	0.90
Total conversion costs			2,906,900	33.31
Total direct costs			3,884,200	44.52
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,796,000	20.59
Average cost of capital and taxes at 8.6% of total capital investment			2,637,600	30.23
Overheads				
Plant, 50% of conversion costs less utilities			892,700	10.23
Administrative, 10% of operating labor			47,200	0.54
Marketing, 10% of sales revenue			59,300	0.68
Total indirect costs			5,432,800	62.27
Gross average annual revenue requirements			9,317,000	106.79
Byproduct Sales Revenue				
Elemental sulfur	14,820 tons	40.00/ton	(592,800)	(6.79)
Net average annual revenue requirements			8,724,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	6.23	14.23	0.68	614

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 613,200 tons/yr, 9,200 Btu/kWh.
- Sulfur removed, 14,220 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $15,476,000; total depreciable investment, $29,933,000; and total capital investment, $30,670,000.
- All tons shown are 2,000 lb.

TABLE A-6

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 200 MW,REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 30670000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14200	14800	36.00	11895400	532800	11362600	11362600
2	7000	12880000	613300	14200	14800	36.00	11723800	532800	11191000	22553600
3	7000	12880000	613300	14200	14800	36.00	11552200	532800	11019400	33573000
4	7000	12880000	613300	14200	14800	36.00	11380600	532800	10847800	44420800
5	7000	12880000	613300	14200	14800	36.00	11209000	532800	10676200	55097000
6	7000	12880000	613300	14200	14800	36.00	11037300	532800	10504500	65601500
7	7000	12880000	613300	14200	14800	36.00	10865700	532800	10332900	75934400
8	7000	12880000	613300	14200	14800	36.00	10694100	532800	10161300	86095700
9	7000	12880000	613300	14200	14800	36.00	10522500	532800	9989700	96085400
10	7000	12880000	613300	14200	14800	36.00	10350800	532800	9818000	105903400
11	5000	9200000	438100	10200	10600	36.00	9090600	381600	8709000	114612400
12	5000	9200000	438100	10200	10600	36.00	8919000	381600	8537400	123149800
13	5000	9200000	438100	10200	10600	36.00	8747400	381600	8365800	131515600
14	5000	9200000	438100	10200	10600	36.00	8575800	381600	8194200	139709800
15	5000	9200000	438100	10200	10600	36.00	8404100	381600	8022500	147732300
16	3500	6440000	306700	7100	7400	36.00	7361500	266400	7095100	154827400
17	3500	6440000	306700	7100	7400	36.00	7189900	266400	6923500	161750900
18	3500	6440000	306700	7100	7400	36.00	7018300	266400	6751900	168502800
19	3500	6440000	306700	7100	7400	36.00	6846700	266400	6580300	175083100
20	3500	6440000	306700	7100	7400	36.00	6675000	266400	6408600	181491700
21	1500	2760000	131400	3000	3200	36.00	5198600	115200	5083400	186575100
22	1500	2760000	131400	3000	3200	36.00	5027000	115200	4911800	191486900
23	1500	2760000	131400	3000	3200	36.00	4855400	115200	4740200	196227100
24	1500	2760000	131400	3000	3200	36.00	4683700	115200	4568500	200795600
25	1500	2760000	131400	3000	3200	36.00	4512100	115200	4396900	205192500
26	1500	2760000	131400	3000	3200	36.00	4340500	115200	4225300	209417800
27	1500	2760000	131400	3000	3200	36.00	4168900	115200	4053700	213471500
28	1500	2760000	131400	3000	3200	36.00	3997300	115200	3882100	217353600
29	1500	2760000	131400	3000	3200	36.00	3825600	115200	3710400	221064000
30	1500	2760000	131400	3000	3200	36.00	3654000	115200	3538800	224602800
TOT	127500	234600000	11171000	258500	270000		234322800	9720000	224602800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	20.98	0.87	20.11
MILLS PER KILOWATT-HOUR	9.19	0.38	8.81
CENTS PER MILLION BTU HEAT INPUT	99.88	4.14	95.74
DOLLARS PER TON OF SULFUR REMOVED	906.47	37.60	868.87

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 83319300 3784600 79534700

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	19.13	0.86	18.27
MILLS PER KILOWATT-HOUR	8.38	0.38	8.00
CENTS PER MILLION BTU HEAT INPUT	91.11	4.13	86.98
DOLLARS PER TON OF SULFUR REMOVED	826.58	37.55	789.03

TABLE A-7. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 500 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	414,000	1.1
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	5,160,000	14.2
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	10,828,000	29.8
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	7,523,000	20.7
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	2,125,000	5.8
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	4,361,000	12.0
Sulfur production (Claus plant with tail gas incinerator)	3,091,000	8.5
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	696,000	1.9
Subtotal	34,198,000	94.0
Services, utilities, and miscellaneous	2,052,000	5.6
Total process area excluding pond construction	36,250,000	99.6
Incremental ash pond cost	157,000	0.4
Total direct investment	36,407,000	100.0
Indirect Investment		
Engineering design and supervision	2,173,000	6.0
Architect and engineering contractor	540,000	1.5
Construction expense	4,950,000	13.6
Contractor fees	1,475,000	4.0
Total indirect investment	9,138,000	25.1
Contingency	9,109,000	25.0
Total fixed investment	54,654,000	150.1
Other Capital Charges		
Allowance for startup and modifications	5,450,000	15.0
Interest during construction	6,558,000	18.1
Total depreciable investment	66,662,000	183.2
Land	59,000	0.2
Working capital	1,528,000	4.2
Total capital investment	68,249,000	187.6

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mile from power plant.
Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-8. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 500 MW, existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	11,020 tons	103.00/ton	1,135,100	5.99
Coal	51,700 tons	25.00/ton	1,292,500	6.82
Catalyst			15,300	0.08
Total raw materials cost			2,442,900	12.89
Conversion costs				
Operating labor and supervision	52,000 man-hr	12.50/man-hr	650,000	3.43
Utilities				
Fuel oil	2,325,000 gal	0.40/gal	930,000	4.91
Process water	178,800 kgal	0.12/kgal	21,500	0.11
Boiler feedwater	69,500 kgal	0.92/kgal	63,900	0.34
Electricity	70,043,000 kWh	0.029/kWh	2,031,200	10.72
Heat credit	205,500 MBtu	2.00/MBtu	(411,000)	(2.17)
Maintenance				
Labor and material			2,542,200	13.41
Analyses	8,760 man-hr	17.00/man-hr	148,900	0.78
Total conversion costs			5,976,700	31.53
Total direct costs			8,419,600	44.41
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			4,266,400	22.51
Average cost of capital and taxes at 8.6% of total capital investment			5,869,400	30.96
Overheads				
Plant, 50% of conversion costs less utilities			1,670,600	8.81
Administrative, 10% of operating labor			65,000	0.34
Marketing, 10% of sales revenue			148,200	0.78
Total indirect costs			12,019,600	63.40
Gross average annual revenue requirements			20,439,200	107.82
Byproduct Sales Revenue				
Elemental sulfur	37,050 tons	40.00/ton	(1,482,000)	(7.82)
Net average annual revenue requirements			18,957,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	5.42	12.36	0.59	533

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
- Sulfur removed, 35,550 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $36,407,000; total depreciable investment, $66,662,000; and total capital investment, $68,249,000.
- All tons shown are 2,000 lb.

TABLE A-9

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 500 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 68249000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	1533300	35600	37100	36.00	26605000	1335600	25269400	25269400
7	7000	32200000	1533300	35600	37100	36.00	26146400	1335600	24810800	50080200
8	7000	32200000	1533300	35600	37100	36.00	25687800	1335600	24352200	74432400
9	7000	32200000	1533300	35600	37100	36.00	25229100	1335600	23893500	98325900
10	7000	32200000	1533300	35600	37100	36.00	24770500	1335600	23436900	121760800
11	5000	23000000	1095200	25400	26500	36.00	21939000	954000	20985000	142745800
12	5000	23000000	1095200	25400	26500	36.00	21480400	954000	20526400	163272200
13	5000	23000000	1095200	25400	26500	36.00	21021800	954000	20067800	183340000
14	5000	23000000	1095200	25400	26500	36.00	20563100	954000	19609100	202949100
15	5000	23000000	1095200	25400	26500	36.00	20104500	954000	19150500	222099600
16	3500	16100000	766700	17800	18500	36.00	17765700	666000	17099700	239199300
17	3500	16100000	766700	17800	18500	36.00	17307100	666000	16641100	255840400
18	3500	16100000	766700	17800	18500	36.00	16848500	666000	16182500	272022900
19	3500	16100000	766700	17800	18500	36.00	16389800	666000	15723800	287746700
20	3500	16100000	766700	17800	18500	36.00	15931200	666000	15265200	303011900
21	1500	6900000	328600	7600	7900	36.00	12701100	284400	12416700	315428600
22	1500	6900000	328600	7600	7900	36.00	12242400	284400	11958000	327386600
23	1500	6900000	328600	7600	7900	36.00	11783800	284400	11499400	338886000
24	1500	6900000	328600	7600	7900	36.00	11325100	284400	11040700	349926700
25	1500	6900000	328600	7600	7900	36.00	10866500	284400	10582100	360508800
26	1500	6900000	328600	7600	7900	36.00	10407900	284400	10123500	370632300
27	1500	6900000	328600	7600	7900	36.00	9949200	284400	9664800	380297100
28	1500	6900000	328600	7600	7900	36.00	9490600	284400	9206200	389503300
29	1500	6900000	328600	7600	7900	36.00	9032000	284400	8747600	398250900
30	1500	6900000	328600	7600	7900	36.00	8573300	284400	8288900	406539800
TOT	92500	425500000	20262000	470000	489500		424161800	17622000	406539800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	20.93	0.87	20.06
MILLS PER KILOWATT-HOUR	9.17	0.38	8.79
CENTS PER MILLION BTU HEAT INPUT	99.69	4.15	95.54
DOLLARS PER TON OF SULFUR REMOVED	902.47	37.49	864.98
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	171131400	7993100	163138300

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	18.64	0.87	17.77
MILLS PER KILOWATT-HOUR	8.17	0.39	7.78
CENTS PER MILLION BTU HEAT INPUT	88.76	4.15	84.61
DOLLARS PER TON OF SULFUR REMOVED	803.06	37.51	765.55

TABLE A-10. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 2.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	255,000	1.1
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	5,084,000	22.9
Fly ash collection (four cyclone dust collectors)	490,000	2.2
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	10,647,000	47.9
ESP credit	(5,885,000)	(26.4)
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	4,265,000	19.3
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	1,254,000	5.6
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	2,497,000	11.2
Sulfur production (Claus plant with tail gas incinerator)	1,797,000	8.1
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	401,000	1.8
Subtotal	20,805,000	93.7
Services, utilities, and miscellaneous	1,248,000	5.6
Total process area excluding pond construction	22,053,000	99.3
Incremental ash pond cost	154,000	0.7
Total direct investment	22,207,000	100.0
Indirect Investment		
Engineering design and supervision	2,082,000	9.4
Architect and engineering contractor	518,000	2.3
Construction expense	3,287,000	14.8
Contractor fees	1,013,000	4.6
Total indirect investment	6,900,000	31.1
Contingency	5,821,000	26.2
Total fixed investment	34,928,000	157.3
Other Capital Charges		
Allowance for startup and modifications	3,477,000	15.7
Interest during construction	4,191,000	18.8
Total depreciable investment	42,596,000	191.8
Land	64,000	0.3
Working capital	923,000	4.2
Total capital investment	43,583,000	196.3

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-11. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 2.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	4,960 tons	103.00/ton	510,900	4.24
Coal	23,270 tons	25.00/ton	581,800	4.84
Catalyst			6,900	0.06
Total raw materials cost			1,099,600	9.14
Conversion costs				
Operating labor and supervision	47,970 man-hr	12.50/man-hr	599,600	4.99
Utilities				
Fuel oil	1,046,000 gal	0.40/gal	418,400	3.48
Process water	80,500 kgal	0.12/kgal	9,700	0.08
Boiler feedwater	31,300 kgal	0.92/kgal	28,800	0.24
Electricity	50,633,200 kWh	0.029/kWh	1,468,400	12.21
Heat credit	92,500 MBtu	2.00/MBtu	(185,000)	(1.54)
Maintenance				
Labor and material			1,548,300	12.87
Analyses	7,850 man-hr	17.00/man-hr	133,500	1.11
Total conversion costs			4,021,700	33.44
Total direct costs			5,121,300	42.58
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,555,800	21.25
Average cost of capital and taxes at 8.6% of total capital investment			3,748,200	31.17
Overheads				
Plant, 50% of conversion costs less utilities			1,140,700	9.49
Administrative, 10% of operating labor			60,000	0.50
Marketing, 10% of sales revenue			66,700	0.55
Total indirect costs			7,571,400	62.96
Gross average annual revenue requirements			12,692,700	105.54
Byproduct Sales Revenue				
Elemental sulfur	16,670 tons	40.00/ton	(666,800)	(5.54)
Net average annual revenue requirements			12,025,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.44	8.02	0.38	752

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Sulfur removed, 16,000 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $22,207,000; total depreciable investment, $42,596,000; and total capital investment, $43,583,000.
- All tons shown are 2,000 lb.

TABLE A-12

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 2.0% S COAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 43583000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	16000	16700	36.00	16374200	601200	15773000	15773000
2	7000	31500000	1500000	16000	16700	36.00	16130000	601200	15528800	31301800
3	7000	31500000	1500000	16000	16700	36.00	15885700	601200	15284500	46586300
4	7000	31500000	1500000	16000	16700	36.00	15641500	601200	15040300	61626600
5	7000	31500000	1500000	16000	16700	36.00	15397300	601200	14796100	76422700
6	7000	31500000	1500000	16000	16700	36.00	15153100	601200	14551900	90974600
7	7000	31500000	1500000	16000	16700	36.00	14908800	601200	14307600	105282200
8	7000	31500000	1500000	16000	16700	36.00	14664600	601200	14063400	119345600
9	7000	31500000	1500000	16000	16700	36.00	14420400	601200	13819200	133164800
10	7000	31500000	1500000	16000	16700	36.00	14176200	601200	13575000	146739800
11	5000	22500000	1071400	11400	11900	36.00	12490100	428400	12061700	158801500
12	5000	22500000	1071400	11400	11900	36.00	12245900	428400	11817500	170619000
13	5000	22500000	1071400	11400	11900	36.00	12001700	428400	11573300	182192300
14	5000	22500000	1071400	11400	11900	36.00	11757500	428400	11329100	193521400
15	5000	22500000	1071400	11400	11900	36.00	11513300	428400	11084900	204606300
16	3500	15750000	750000	8000	8300	36.00	10119400	298800	9820600	214426900
17	3500	15750000	750000	8000	8300	36.00	9875200	298800	9576400	224003300
18	3500	15750000	750000	8000	8300	36.00	9631000	298800	9332200	233335500
19	3500	15750000	750000	8000	8300	36.00	9386800	298800	9088000	242423500
20	3500	15750000	750000	8000	8300	36.00	9142500	298800	8843700	251267200
21	1500	6750000	321400	3400	3600	36.00	7185100	129600	7055500	258322700
22	1500	6750000	321400	3400	3600	36.00	6940900	129600	6811300	265134000
23	1500	6750000	321400	3400	3600	36.00	6696700	129600	6567100	271701100
24	1500	6750000	321400	3400	3600	36.00	6452500	129600	6322900	278024000
25	1500	6750000	321400	3400	3600	36.00	6208200	129600	6078600	284102600
26	1500	6750000	321400	3400	3600	36.00	5964000	129600	5834400	289937000
27	1500	6750000	321400	3400	3600	36.00	5719800	129600	5590200	295527200
28	1500	6750000	321400	3400	3600	36.00	5475600	129600	5346000	300873200
29	1500	6750000	321400	3400	3600	36.00	5231300	129600	5101700	305974900
30	1500	6750000	321400	3400	3600	36.00	4987100	129600	4857500	310832400
TOT	127500	573750000	27321000	291000	304000		321776400	10944000	310832400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	11.78	0.40	11.38
MILLS PER KILOWATT-HOUR	5.05	0.17	4.88
CENTS PER MILLION BTU HEAT INPUT	56.08	1.90	54.18
DOLLARS PER TON OF SULFUR REMOVED	1105.76	37.61	1068.15
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	114459300	4266300	110193000

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	10.75	0.40	10.35
MILLS PER KILOWATT-HOUR	4.61	0.18	4.43
CENTS PER MILLION BTU HEAT INPUT	51.18	1.91	49.27
DOLLARS PER TON OF SULFUR REMOVED	1008.45	37.59	970.86

TABLE A-13. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Base case: 500 MW, 3.5% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	409,000	1.3
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	5,084,000	16.2
Fly ash collection (four cyclone dust collectors)	490,000	1.6
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	10,647,000	33.9
ESP credit	(4,713,000)	(15.0)
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	7,405,000	23.6
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	2,094,000	6.7
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	4,297,000	13.7
Sulfur production (Claus plant with tail gas incinerator)	3,045,000	9.7
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	686,000	2.2
Subtotal	29,444,000	93.9
Services, utilities, and miscellaneous	1,767,000	5.6
Total process area excluding pond construction	31,211,000	99.5
Incremental ash pond cost	154,000	0.5
Total direct investment	31,365,000	100.0
Indirect Investment		
Engineering design and supervision	2,170,000	6.9
Architect and engineering contractor	539,000	1.7
Construction expense	4,375,000	14.0
Contractor fees	1,317,000	4.2
Total indirect investment	8,401,000	26.8
Contingency	7,953,000	25.3
Total fixed investment	47,719,000	152.1
Other Capital Charges		
Allowance for startup and modifications	4,757,000	15.2
Interest during construction	5,726,000	18.3
Total depreciable investment	58,202,000	185.6
Land	64,000	0.2
Working capital	1,436,000	4.6
Total capital investment	59,702,000	190.4

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-14. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Base case: 500 MW, 3.5% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	10,780 tons	103.00/ton	1,110,300	6.60
Coal	50,580 tons	25.00/ton	1,264,500	7.52
Catalyst			15,000	0.09
Total raw materials cost			2,389,800	14.21
Conversion costs				
Operating labor and supervision	52,000 man-hr	12.50/man-hr	650,000	3.86
Utilities				
Fuel oil	2,274,000 gal	0.40/gal	909,600	5.41
Process water	174,900 kgal	0.12/kgal	21,000	0.12
Boiler feedwater	68,000 kgal	0.92/kgal	62,600	0.37
Electricity	67,920,000 kWh	0.029/kWh	1,969,700	11.71
Heat credit	201,000 MBtu	2.00/MBtu	(402,000)	(2.39)
Maintenance				
Labor and material			2,189,400	13.02
Analyses	8,760 man-hr	17.00/man-hr	148,900	0.89
Total conversion costs			5,549,200	32.99
Total direct costs			7,939,000	47.20
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,492,100	20.76
Average cost of capital and taxes at 8.6% of total capital investment			5,134,400	30.53
Overheads				
Plant, 50% of conversion costs less utilities			1,494,200	8.88
Administrative, 10% of operating labor			65,000	0.39
Marketing, 10% of sales revenue			145,000	0.86
Total indirect costs			10,330,700	61.42
Gross average annual revenue requirements			18,269,700	108.62
Byproduct Sales Revenue				
Elemental sulfur	36,240 tons	40.00/ton	(1,449,600)	(8.62)
Net average annual revenue requirements			16,820,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.81	11.21	0.53	484

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $31,365,000; total depreciable investment, $58,202,000; and total capital investment, $59,702,000.
- All tons shown are 2,000 lb.

TABLE A-15

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS BASE CASE:500 MW, 3.5% S COAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 59702000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	36200	36.00	23259200	1303200	21956000	21956000
2	7000	31500000	1500000	34800	36200	36.00	22925500	1303200	21622300	43578300
3	7000	31500000	1500000	34800	36200	36.00	22591800	1303200	21288600	64866900
4	7000	31500000	1500000	34800	36200	36.00	22258200	1303200	20955000	85821900
5	7000	31500000	1500000	34800	36200	36.00	21924500	1303200	20621300	106443200
6	7000	31500000	1500000	34800	36200	36.00	21590800	1303200	20287600	126730800
7	7000	31500000	1500000	34800	36200	36.00	21257100	1303200	19953900	146684700
8	7000	31500000	1500000	34800	36200	36.00	20923400	1303200	19620200	166304900
9	7000	31500000	1500000	34800	36200	36.00	20589700	1303200	19286500	185591400
10	7000	31500000	1500000	34800	36200	36.00	20256000	1303200	18952800	204544200
11	5000	22500000	1071400	24800	25900	36.00	17682600	932400	16750200	221294400
12	5000	22500000	1071400	24800	25900	36.00	17348900	932400	16416500	237710900
13	5000	22500000	1071400	24800	25900	36.00	17015200	932400	16082800	253793700
14	5000	22500000	1071400	24800	25900	36.00	16681500	932400	15749100	269542800
15	5000	22500000	1071400	24800	25900	36.00	16347800	932400	15415400	284958200
16	3500	15750000	750000	17400	18100	36.00	14244900	651600	13593300	298551500
17	3500	15750000	750000	17400	18100	36.00	13911200	651600	13259600	311811100
18	3500	15750000	750000	17400	18100	36.00	13577500	651600	12925900	324737000
19	3500	15750000	750000	17400	18100	36.00	13243800	651600	12592200	337329200
20	3500	15750000	750000	17400	18100	36.00	12910100	651600	12258500	349587700
21	1500	6750000	321400	7500	7800	36.00	9980500	280800	9699700	359287400
22	1500	6750000	321400	7500	7800	36.00	9646800	280800	9366000	368653400
23	1500	6750000	321400	7500	7800	36.00	9313100	280800	9032300	377685700
24	1500	6750000	321400	7500	7800	36.00	8979400	280800	8698600	386384300
25	1500	6750000	321400	7500	7800	36.00	8645700	280800	8364900	394749200
26	1500	6750000	321400	7500	7800	36.00	8312000	280800	8031200	402780400
27	1500	6750000	321400	7500	7800	36.00	7978300	280800	7697500	410477900
28	1500	6750000	321400	7500	7800	36.00	7644600	280800	7363800	417841700
29	1500	6750000	321400	7500	7800	36.00	7310900	280800	7030100	424871800
30	1500	6750000	321400	7500	7800	36.00	6977200	280800	6696400	431568200
TOT	127500	573750000	27321000	634000	660000		455328200	23760000	431568200	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	16.67	0.87	15.80
MILLS PER KILOWATT-HOUR	7.14	0.37	6.77
CENTS PER MILLION BTU HEAT INPUT	79.36	4.14	75.22
DOLLARS PER TON OF SULFUR REMOVED	718.18	37.47	680.71

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 162629800 9255200 153374600

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	15.27	0.87	14.40
MILLS PER KILOWATT-HOUR	6.54	0.37	6.17
CENTS PER MILLION BTU HEAT INPUT	72.72	4.14	68.58
DOLLARS PER TON OF SULFUR REMOVED	658.42	37.47	620.95

TABLE A-16. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 5.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	532,000	1.4
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	5,084,000	13.4
Fly ash collection (four cyclone dust collectors)	490,000	1.3
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	10,647,000	28.0
ESP credit	(4,713,000)	(12.4)
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	10,056,000	26.5
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	2,783,000	7.3
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	5,810,000	15.4
Sulfur production (Claus plant with tail gas incinerator)	4,080,000	10.7
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	923,000	2.4
Subtotal	35,692,000	94.0
Services, utilities, and miscellaneous	2,142,000	5.6
Total process area excluding pond construction	37,834,000	99.6
Incremental ash pond cost	154,000	0.4
Total direct investment	37,988,000	100.0
Indirect Investment		
Engineering design and supervision	2,242,000	5.9
Architect and engineering contractor	557,000	1.5
Construction expense	5,128,000	13.5
Contractor fees	1,523,000	4.0
Total indirect investment	9,450,000	24.9
Contingency	9,488,000	25.0
Total fixed investment	56,926,000	149.9
Other Capital Charges		
Allowance for startup and modifications	5,677,000	14.9
Interest during construction	6,831,000	18.0
Total depreciable investment	69,434,000	182.8
Land	64,000	0.2
Working capital	1,912,000	5.0
Total capital investment	71,410,000	188.0

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mile from power plant.
Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-17. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 5.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	16,580 tons	103.00/ton	1,707,700	8.25
Coal	77,790 tons	25.00/ton	1,944,800	9.39
Catalyst			23,100	0.11
Total raw materials cost			3,675,600	17.75
Conversion costs				
Operating labor and supervision	54,870 man-hr	12.50/man-hr	685,900	3.31
Utilities				
Fuel oil	3,498,000 gal	0.40/gal	1,399,200	6.76
Process water	269,000 kgal	0.12/kgal	32,300	0.16
Boiler feedwater	104,600 kgal	0.92/kgal	96,200	0.46
Electricity	86,377,000 kWh	0.029/kWh	2,504,900	12.10
Heat credit	309,200 MBtu	2.00/MBtu	(618,400)	(2.99)
Maintenance				
Labor and material			2,653,000	12.81
Analyses	9,410 man-hr	17.00/man-hr	160,000	0.77
Total conversion costs			6,913,100	33.38
Total direct costs			10,588,700	51.13
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,166,000	20.12
Average cost of capital and taxes at 8.6% of total capital investment			6,141,300	29.66
Overheads				
Plant, 50% of conversion costs less utilities			1,749,500	8.45
Administrative, 10% of operating labor			68,600	0.33
Marketing, 10% of sales revenue			223,000	1.08
Total indirect costs			12,348,400	59.64
Gross average annual revenue requirements			22,937,100	110.77
Byproduct Sales Revenue				
Elemental sulfur	55,740 tons	40.00/ton	(2,229,600)	(10.77)
Net average annual revenue requirements			20,707,500	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	5.92	13.80	0.66	387

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Sulfur removed, 53,500 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $37,988,000; total depreciable investment, $69,434,000; and total capital investment, $71,410,000.
- All tons shown are 2,000 lb.

TABLE A-18

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 5.0% S COAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 71410000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	53500	55700	36.00	28855600	2005200	26850400	26850400
2	7000	31500000	1500000	53500	55700	36.00	28457500	2005200	26452300	53302700
3	7000	31500000	1500000	53500	55700	36.00	28059400	2005200	26054200	79356900
4	7000	31500000	1500000	53500	55700	36.00	27661300	2005200	25656100	105013000
5	7000	31500000	1500000	53500	55700	36.00	27263200	2005200	25258000	130271000
6	7000	31500000	1500000	53500	55700	36.00	26865200	2005200	24860000	155131000
7	7000	31500000	1500000	53500	55700	36.00	26467100	2005200	24461900	179592900
8	7000	31500000	1500000	53500	55700	36.00	26069000	2005200	24063800	203656700
9	7000	31500000	1500000	53500	55700	36.00	25670900	2005200	23665700	227322400
10	7000	31500000	1500000	53500	55700	36.00	25272800	2005200	23267600	250590000
11	5000	22500000	1071400	38200	39800	36.00	21883000	1432800	20450200	271040200
12	5000	22500000	1071400	38200	39800	36.00	21484900	1432800	20052100	291092300
13	5000	22500000	1071400	38200	39800	36.00	21086800	1432800	19654000	310746300
14	5000	22500000	1071400	38200	39800	36.00	20688700	1432800	19255900	330002200
15	5000	22500000	1071400	38200	39800	36.00	20290600	1432800	18857800	348860000
16	3500	15750000	750000	26800	27900	36.00	17543900	1004400	16539500	365399500
17	3500	15750000	750000	26800	27900	36.00	17145800	1004400	16141400	381540900
18	3500	15750000	750000	26800	27900	36.00	16747700	1004400	15743300	397284200
19	3500	15750000	750000	26800	27900	36.00	16349600	1004400	15345200	412629400
20	3500	15750000	750000	26800	27900	36.00	15951500	1004400	14947100	427576500
21	1500	6750000	321400	11500	11900	36.00	12144800	428400	11716400	439292900
22	1500	6750000	321400	11500	11900	36.00	11746700	428400	11318300	450611200
23	1500	6750000	321400	11500	11900	36.00	11348700	428400	10920300	461531500
24	1500	6750000	321400	11500	11900	36.00	10950600	428400	10522200	472053700
25	1500	6750000	321400	11500	11900	36.00	10552500	428400	10124100	482177800
26	1500	6750000	321400	11500	11900	36.00	10154400	428400	9726000	491903800
27	1500	6750000	321400	11500	11900	36.00	9756300	428400	9327900	501231700
28	1500	6750000	321400	11500	11900	36.00	9358200	428400	8929800	510161500
29	1500	6750000	321400	11500	11900	36.00	8960100	428400	8531700	518693200
30	1500	6750000	321400	11500	11900	36.00	8562000	428400	8133600	526826800
TOT	127500	573750000	27321000	975000	1014500		563348800	36522000	526826800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	20.62	1.34	19.28
MILLS PER KILOWATT-HOUR	8.84	0.58	8.26
CENTS PER MILLION BTU HEAT INPUT	98.19	6.37	91.82
DOLLARS PER TON OF SULFUR REMOVED	577.79	37.45	540.34
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	201873100	14237500	187635600

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	18.96	1.34	17.62
MILLS PER KILOWATT-HOUR	8.12	0.57	7.55
CENTS PER MILLION BTU HEAT INPUT	90.27	6.37	83.90
DOLLARS PER TON OF SULFUR REMOVED	531.38	37.47	493.91

TABLE A-19. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	624,000	1.1
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	8,145,000	13.9
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	17,908,000	30.5
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	12,115,000	20.7
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	3,309,000	5.6
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	6,983,000	11.9
Sulfur production (Claus plant with tail gas incinerator)	4,878,000	8.3
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	1,107,000	1.9
Subtotal	55,069,000	93.9
Services, utilities, and miscellaneous	3,304,000	5.6
Total process area excluding pond construction	58,373,000	99.5
Incremental ash pond cost	308,000	0.5
Total direct investment	58,681,000	100.0
Indirect Investment		
Engineering design and supervision	3,704,000	6.3
Architect and engineering contractor	921,000	1.6
Construction expense	7,358,000	12.5
Contractor fees	2,120,000	3.6
Total indirect investment	14,103,000	24.0
Contingency	14,557,000	24.8
Total fixed investment	87,341,000	148.8
Other Capital Charges		
Allowance for startup and modifications	8,703,000	14.8
Interest during construction	10,481,000	17.9
Total depreciable investment	106,885,000	181.5
Land	105,000	0.2
Working capital	2,573,000	4.4
Total capital investment	109,563,000	186.1

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-20. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	21,560 tons	103.00/ton	2,220,700	7.30
Coal	101,150 tons	25.00/ton	2,528,800	8.31
Catalyst			30,000	0.10
Total raw materials cost			4,779,500	15.71
Conversion costs				
Operating labor and supervision	68,000 man-hr	12.50/man-hr	850,000	2.79
Utilities				
Fuel oil	4,548,000 gal	0.40/gal	1,819,200	5.98
Process water	349,800 kgal	0.12/kgal	42,000	0.14
Boiler feedwater	136,000 kgal	0.92/kgal	125,100	0.41
Electricity	136,469,000 kWh	0.028/kWh	3,821,100	12.56
Heat credit	402,100 MBtu	2.00/MBtu	(804,200)	(2.64)
Maintenance				
Labor and material			3,511,600	11.54
Analyses	14,230 man-hr	17.00/man-hr	241,900	0.79
Total conversion costs			9,606,700	31.57
Total direct costs			14,386,200	47.28
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			6,840,600	22.48
Average cost of capital and taxes at 8.6% of total capital investment			9,422,400	30.97
Overheads				
Plant, 50% of conversion costs less utilities			2,301,800	7.57
Administrative, 10% of operating labor			85,000	0.28
Marketing, 10% of sales revenue			289,900	0.95
Total indirect costs			18,939,700	62.25
Gross average annual revenue requirements			33,325,900	109.53
Byproduct Sales Revenue				
Elemental sulfur	72,480 tons	40.00/ton	(2,899,200)	(9.53)
Net average annual revenue requirements			30,426,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	4.35	10.14	0.48	437

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,999,900 tons/yr, 9,000 Btu/kWh.
- Sulfur removed, 69,560 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $58,681,000; total depreciable investment, $106,885,000; and total capital investment, $109,563,000.
- All tons shown are 2,000 lb.

TABLE A-21

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 1000 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 109563000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	63000000	3000000	69600	72500	36.00	43171400	2610000	40561400	40561400
7	7000	63000000	3000000	69600	72500	36.00	42436100	2610000	39826100	80387500
8	7000	63000000	3000000	69600	72500	36.00	41700700	2610000	39090700	119478200
9	7000	63000000	3000000	69600	72500	36.00	40965300	2610000	38355300	157833500
10	7000	63000000	3000000	69600	72500	36.00	40230000	2610000	37620000	195453500
11	5000	45000000	2142900	49700	51800	36.00	35422500	1864800	33557700	229011200
12	5000	45000000	2142900	49700	51800	36.00	34687100	1864800	32822300	261833500
13	5000	45000000	2142900	49700	51800	36.00	33951800	1864800	32087000	293920500
14	5000	45000000	2142900	49700	51800	36.00	33216400	1864800	31351600	325272100
15	5000	45000000	2142900	49700	51800	36.00	32481000	1864800	30616200	355888300
16	3500	31500000	1500000	34800	36200	36.00	28554400	1303200	27251200	383139500
17	3500	31500000	1500000	34800	36200	36.00	27819100	1303200	26515900	409655400
18	3500	31500000	1500000	34800	36200	36.00	27083700	1303200	25780500	435435900
19	3500	31500000	1500000	34800	36200	36.00	26348300	1303200	25045100	460481000
20	3500	31500000	1500000	34800	36200	36.00	25613000	1303200	24309800	484790800
21	1500	13500000	642900	14900	15500	36.00	20261800	558000	19703800	504494600
22	1500	13500000	642900	14900	15500	36.00	19526400	558000	18968400	523463000
23	1500	13500000	642900	14900	15500	36.00	18791100	558000	18233100	541696100
24	1500	13500000	642900	14900	15500	36.00	18055700	558000	17497700	559193800
25	1500	13500000	642900	14900	15500	36.00	17320300	558000	16762300	575956100
26	1500	13500000	642900	14900	15500	36.00	16585000	558000	16027000	591983100
27	1500	13500000	642900	14900	15500	36.00	15849600	558000	15291600	607274700
28	1500	13500000	642900	14900	15500	36.00	15114200	558000	14556200	621830900
29	1500	13500000	642900	14900	15500	36.00	14378900	558000	13820900	635651800
30	1500	13500000	642900	14900	15500	36.00	13643500	558000	13085500	648737300
TOT	92500	832500000	39643500	919500	957500		683207300	34470000	648737300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	17.23	0.87	16.36
MILLS PER KILOWATT-HOUR	7.39	0.38	7.01
CENTS PER MILLION BTU HEAT INPUT	82.07	4.14	77.93
DOLLARS PER TON OF SULFUR REMOVED	743.02	37.49	705.53
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	276745400	15625500	261119900

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	15.41	0.87	14.54
MILLS PER KILOWATT-HOUR	6.60	0.37	6.23
CENTS PER MILLION BTU HEAT INPUT	73.36	4.14	69.22
DOLLARS PER TON OF SULFUR REMOVED	664.14	37.50	626.64

TABLE A-22. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	611,000	1.2
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	7,962,000	16.2
Fly ash collection (four cyclone dust collectors)	830,000	1.7
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	17,461,000	35.6
ESP credit	(8,526,000)	(17.4)
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	11,826,000	24.1
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	3,235,000	6.6
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	6,815,000	13.9
Sulfur production (Claus plant with tail gas incinerator)	4,768,000	9.7
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	1,081,000	2.2
Subtotal	46,063,000	93.8
Services, utilities, and miscellaneous	2,764,000	5.6
Total process area excluding pond construction	48,827,000	99.4
Incremental ash pond cost	298,000	0.6
Total direct investment	49,125,000	100.0
Indirect Investment		
Engineering design and supervision	3,696,000	7.5
Architect and engineering contractor	919,000	1.9
Construction expense	6,350,000	12.9
Contractor fees	1,852,000	3.8
Total indirect investment	12,817,000	26.1
Contingency	12,388,000	25.2
Total fixed investment	74,330,000	151.3
Other Capital Charges		
Allowance for startup and modifications	7,403,000	15.1
Interest during construction	8,920,000	18.1
Total depreciable investment	90,653,000	184.5
Land	105,000	0.2
Working capital	2,403,000	4.9
Total capital investment	93,161,000	189.6

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mile from power plant.
Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-23. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	20,840 tons	103.00/ton	2,146,500	8.09
Coal	97,780 tons	25.00/ton	2,444,500	9.22
Catalyst			29,000	0.11
Total raw materials cost			4,620,000	17.42
Conversion costs				
Operating labor and supervision	68,000 man-hr	12.50/man-hr	850,000	3.21
Utilities				
Fuel oil	4,396,700 gal	0.40/gal	1,758,700	6.63
Process water	338,100 kgal	0.12/kgal	40,600	0.15
Boiler feedwater	131,500 kgal	0.92/kgal	121,000	0.46
Electricity	131,938,000 kWh	0.028/kWh	3,694,300	13.93
Heat credit	388,700 MBtu	2.00/MBtu	(777,400)	(2.93)
Maintenance				
Labor and material			2,938,600	11.08
Analyses	14,230 man-hr	17.00/man-hr	241,900	0.91
Total conversion costs			8,867,700	33.44
Total direct costs			13,487,700	50.86
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			5,439,200	20.51
Average cost of capital and taxes at 8.6% of total capital investment			8,011,800	30.21
Overheads				
Plant, 50% of conversion costs less utilities			2,015,300	7.60
Administrative, 10% of operating labor			85,000	0.32
Marketing, 10% of sales revenue			280,200	1.06
Total indirect costs			15,831,500	59.70
Gross average annual revenue requirements			29,319,200	110.56
Byproduct Sales Revenue				
Elemental sulfur	70,060 tons	40.00/ton	(2 802,400)	(10.56)
Net average annual revenue requirements			26,516,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.79	9.14	0.44	394

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
- Sulfur removed, 67,240 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $49,125,000; total depreciable investment, $90,653,000; and total capital investment, $93,161,000.
- All tons shown are 2,000 lb.

TABLE A-24

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 1000 MW, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 93161000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67200	70100	36.00	37051200	2523600	34527600	34527600
2	7000	60900000	2900000	67200	70100	36.00	36531400	2523600	34007800	68535400
3	7000	60900000	2900000	67200	70100	36.00	36011700	2523600	33488100	102023500
4	7000	60900000	2900000	67200	70100	36.00	35491900	2523600	32968300	134991800
5	7000	60900000	2900000	67200	70100	36.00	34972200	2523600	32448600	167440400
6	7000	60900000	2900000	67200	70100	36.00	34452400	2523600	31928800	199369200
7	7000	60900000	2900000	67200	70100	36.00	33932700	2523600	31409100	230778300
8	7000	60900000	2900000	67200	70100	36.00	33412900	2523600	30889300	261667600
9	7000	60900000	2900000	67200	70100	36.00	32893200	2523600	30369600	292037200
10	7000	60900000	2900000	67200	70100	36.00	32373400	2523600	29849800	321887000
11	5000	43500000	2071400	48000	50000	36.00	28031500	1800000	26231500	348118500
12	5000	43500000	2071400	48000	50000	36.00	27511700	1800000	25711700	373830200
13	5000	43500000	2071400	48000	50000	36.00	26992000	1800000	25192000	399022200
14	5000	43500000	2071400	48000	50000	36.00	26472200	1800000	24672200	423694400
15	5000	43500000	2071400	48000	50000	36.00	25952500	1800000	24152500	447846900
16	3500	30450000	1450000	33600	35000	36.00	22446700	1260000	21186700	469033600
17	3500	30450000	1450000	33600	35000	36.00	21927000	1260000	20667000	489700600
18	3500	30450000	1450000	33600	35000	36.00	21407200	1260000	20147200	509847800
19	3500	30450000	1450000	33600	35000	36.00	20887500	1260000	19627500	529475300
20	3500	30450000	1450000	33600	35000	36.00	20367700	1260000	19107700	548583000
21	1500	13050000	621400	14400	15000	36.00	15551200	540000	15011200	563594200
22	1500	13050000	621400	14400	15000	36.00	15031500	540000	14491500	578085700
23	1500	13050000	621400	14400	15000	36.00	14511700	540000	13971700	592057400
24	1500	13050000	621400	14400	15000	36.00	13992000	540000	13452000	605509400
25	1500	13050000	621400	14400	15000	36.00	13472200	540000	12932200	618441600
26	1500	13050000	621400	14400	15000	36.00	12952500	540000	12412500	630854100
27	1500	13050000	621400	14400	15000	36.00	12432700	540000	11892700	642746800
28	1500	13050000	621400	14400	15000	36.00	11913000	540000	11373000	654119800
29	1500	13050000	621400	14400	15000	36.00	11393200	540000	10853200	664973000
30	1500	13050000	621400	14400	15000	36.00	10873500	540000	10333500	675306500
TOT	127500	1109250000	52821000	1224000	1276000		721242500	45936000	675306500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	13.65	0.87	12.78
MILLS PER KILOWATT-HOUR	5.66	0.36	5.30
CENTS PER MILLION BTU HEAT INPUT	65.02	4.14	60.88
DOLLARS PER TON OF SULFUR REMOVED	589.25	37.53	551.72
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	258817000	17912100	240904900

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	12.57	0.87	11.70
MILLS PER KILOWATT-HOUR	5.21	0.36	4.85
CENTS PER MILLION BTU HEAT INPUT	59.86	4.14	55.72
DOLLARS PER TON OF SULFUR REMOVED	542.48	37.54	504.94

TABLE A-25. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	443,000	1.3
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	5,084,000	15.3
Fly ash collection (four cyclone dust collectors)	490,000	1.5
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	10,647,000	32.1
ESP credit	(4,713,000)	(14.2)
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	8,123,000	24.5
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	2,282,000	6.9
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	4,710,000	14.2
Sulfur production (Claus plant with tail gas incinerator)	3,328,000	10.0
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	750,000	2.3
Subtotal	31,144,000	93.9
Services, utilities, and miscellaneous	1,869,000	5.6
Total process area excluding pond construction	33,013,000	99.5
Incremental ash pond cost	154,000	0.5
Total direct investment	33,167,000	100.0
Indirect Investment		
Engineering design and supervision	2,190,000	6.6
Architect and engineering contractor	544,000	1.6
Construction expense	4,582,000	13.9
Contractor fees	1,374,000	4.1
Total indirect investment	8,690,000	26.2
Contingency	8,371,000	25.2
Total fixed investment	50,228,000	151.4
Other Capital Charges		
Allowance for startup and modifications	5,007,000	15.1
Interest during construction	6,027,000	18.2
Total depreciable investment	61,262,000	184.7
Land	64,000	0.2
Working capital	1,560,000	4.7
Total capital investment	62,886,000	185.6

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Minimum in-process storage; only pumps are spared.
Disposal pond located 1 mile from power plant.
Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-26. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	12,280 tons	103.00/ton	1,264,800	7.09
Coal	57,620 tons	25.00/ton	1,440,500	8.07
Catalyst			17,100	0.10
Total raw materials cost			2,722,400	15.26
Conversion costs				
Operating labor and supervision	52,000 man-hr	12.50/man-hr	650,000	3.64
Utilities				
Fuel oil	2,590,800 gal	0.40/gal	1,036,300	5.81
Process water	199,300 kgal	0.12/kgal	23,900	0.13
Boiler feedwater	77,500 kgal	0.92/kgal	71,300	0.40
Electricity	73,150,000 kWh	0.029/kWh	2,121,400	11.88
Heat credit	229,000 MBtu	2.00/MBtu	(458,000)	(2.57)
Maintenance				
Labor and material			2,315,500	12.97
Analyses	8,760 man-hr	17.00/man-hr	148,900	0.83
Total conversion costs			5,909,300	33.09
Total direct costs			8,631,700	48.35
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,675,700	20.59
Average cost of capital and taxes at 8.6% of total capital investment			5,408,200	30.30
Overheads				
Plant, 50% of conversion costs less utilities			1,557,200	8.72
Administrative, 10% of operating labor			65,000	0.36
Marketing, 10% of sales revenue			165,200	0.93
Total indirect costs			10,871,300	60.90
Gross average annual revenue requirements			19,503,000	109.25
Byproduct Sales Revenue				
Elemental sulfur	41,290 tons	40.00/ton	(1,651,600)	(9.25)
Net average annual revenue requirements			17,851,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	5.10	11.90	0.57	451

Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 30 yr.
Power unit on-stream time, 7,000 hr/yr.
Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
Sulfur removed, 39,620 short tons/yr.
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $33,167,000; total depreciable investment, $61,262,000; and total capital investment, $62,886,000.
All tons shown are 2,000 lb.

TABEL A-27

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: 90% S REMOVAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 62886000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	39600	41300	36.00	24746300	1486800	23259500	23259500
2	7000	31500000	1500000	39600	41300	36.00	24395100	1486800	22908300	46167800
3	7000	31500000	1500000	39600	41300	36.00	24043800	1486800	22557000	68724800
4	7000	31500000	1500000	39600	41300	36.00	23692600	1486800	22205800	90930600
5	7000	31500000	1500000	39600	41300	36.00	23341300	1486800	21854500	112785100
6	7000	31500000	1500000	39600	41300	36.00	22990100	1486800	21503300	134288400
7	7000	31500000	1500000	39600	41300	36.00	22638800	1486800	21152000	155440400
8	7000	31500000	1500000	39600	41300	36.00	22287600	1486800	20800800	176241200
9	7000	31500000	1500000	39600	41300	36.00	21936400	1486800	20449600	196690800
10	7000	31500000	1500000	39600	41300	36.00	21585100	1486800	20098300	216789100
11	5000	22500000	1071400	28300	29500	36.00	18797900	1062000	17735900	234525000
12	5000	22500000	1071400	28300	29500	36.00	18446600	1062000	17384600	251909600
13	5000	22500000	1071400	28300	29500	36.00	18095400	1062000	17033400	268943000
14	5000	22500000	1071400	28300	29500	36.00	17744200	1062000	16682200	285625200
15	5000	22500000	1071400	28300	29500	36.00	17392900	1062000	16330900	301956100
16	3500	15750000	750000	19800	20600	36.00	15121400	741600	14379800	316335900
17	3500	15750000	750000	19800	20600	36.00	14770100	741600	14028500	330364400
18	3500	15750000	750000	19800	20600	36.00	14418900	741600	13677300	344041700
19	3500	15750000	750000	19800	20600	36.00	14067700	741600	13326100	357367800
20	3500	15750000	750000	19800	20600	36.00	13716400	741600	12974800	370342600
21	1500	6750000	321400	8500	8800	36.00	10557700	316800	10240900	380583500
22	1500	6750000	321400	8500	8800	36.00	10206400	316800	9889600	390473100
23	1500	6750000	321400	8500	8800	36.00	9855200	316800	9538400	400011500
24	1500	6750000	321400	8500	8800	36.00	9503900	316800	9187100	409198600
25	1500	6750000	321400	8500	8800	36.00	9152700	316800	8835900	418034500
26	1500	6750000	321400	8500	8800	36.00	8801500	316800	8484700	426519200
27	1500	6750000	321400	8500	8800	36.00	8450200	316800	8133400	434652600
28	1500	6750000	321400	8500	8800	36.00	8099000	316800	7782200	442434800
29	1500	6750000	321400	8500	8800	36.00	7747700	316800	7430900	449865700
30	1500	6750000	321400	8500	8800	36.00	7396500	316800	7079700	456945400
TOT	127500	573750000	27321000	721500	751500		483999400	27054000	456945400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	17.72	0.99	16.73
MILLS PER KILOWATT-HOUR	7.59	0.42	7.17
CENTS PER MILLION BTU HEAT INPUT	84.36	4.72	79.64
DOLLARS PER TON OF SULFUR REMOVED	670.82	37.49	633.33
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	173046200	10553500	162492700

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	16.25	0.99	15.26
MILLS PER KILOWATT-HOUR	6.96	0.42	6.54
CENTS PER MILLION BTU HEAT INPUT	77.38	4.72	72.66
DOLLARS PER TON OF SULFUR REMOVED	615.38	37.53	577.85

TABLE A-28. AQUEOUS CARBONATE PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: oil-fired, existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling and feed preparation (tank and pumps)	248,000	1.0
Gas handling (common feed plenum, gas ducts and dampers from plenum to spray dryer, exhaust gas ducts and dampers from ESP's to stack, and booster fans)	4,540,000	17.8
SO_2 absorption and removal (four spray dryers, four ESP's, silos, hopper, conveyors, tank, agitator, and pumps)	9,401,000	36.8
Reduction (reducers, compressors, reducer-recuperators, waste heat boilers, reducer air heater, tanks, agitators, and pumps)	4,139,000	16.2
Off-gas treatment (venturi scrubber, cooling tower, heat exchangers, and pumps)	1,219,000	4.8
Carbonation (precarbonator, crystallizer, carbonator, decomposer, filter, heat exchangers, compressor, and pumps)	2,424,000	9.5
Sulfur production (Claus plant with tail gas incinerator)	1,745,000	6.8
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	390,000	1.5
Subtotal	24,106,000	94.3
Services, utilities, and miscellaneous	1,446,000	5.7
Total direct investment	25,552,000	100.0
Indirect Investment		
Engineering design and supervision	2,057,000	8.1
Architect and engineering contractor	514,000	2.0
Construction expense	3,682,000	14.4
Contractor fees	1,127,000	4.4
Total indirect investment	7,380,000	28.9
Contingency	6,586,000	25.8
Total fixed investment	39,518,000	154.7
Other Capital Charges		
Allowance for startup and modifications	3,952,000	15.5
Interest during construction	4,742,000	18.6
Total depreciable investment	48,212,000	188.8
Land	41,000	0.2
Working capital	946,000	3.7
Total capital investment	49,199,000	192.7

Basis

Midwest plant location represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Minimum in-process storage; only pumps are spared.

Disposal pond located 1 mile from power plant.

Investment requirement for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-29. AQUEOUS CARBONATE PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: oil-fired, existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Soda ash	4,750 tons	103.00/ton	489,300	3.69
Coal	22,290 tons	25.00/ton	557,300	4.21
Catalyst			6,600	0.05
Total raw materials cost			1,053,200	7.95
Conversion costs				
Operating labor and supervision	50,320 man-hr	12.50/man-hr	629,000	4.74
Utilities				
Fuel oil	1,002,500 gal	0.40/gal	401,000	3.02
Process water	77,100 kgal	0.12/kgal	9,300	0.10
Boiler feedwater	30,000 kgal	0.92/kgal	27,600	0.21
Electricity	44,672,000 kWh	0.029/kWh	1,295,500	9.77
Heat credit	88,600 MBtu	2.00/MBtu	(177,200)	1.34
Maintenance				
Labor and material			1,788,600	13.49
Analyses	8,380 man-hr	17.00/man-hr	142,500	1.07
Total conversion costs			4,116,300	31.06
Total direct costs			5,169,500	39.00
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			3,035,600	23.28
Average cost of capital and taxes at 8.6% of total capital investment			4,231,000	31.93
Overheads				
Plant, 50% of conversion costs less utilities			1,280,100	9.66
Administrative, 10% of operating labor			62,900	0.47
Marketing, 10% of sales revenue			63,900	0.48
Total indirect costs			8,723,600	65.82
Gross average annual revenue requirements			13,893,100	104.82
Byproduct Sales Revenue				
Elemental sulfur	15,980 tons	40.00/ton	(639,200)	(4.82)
Net average annual revenue requirements			13,253,900	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements	3.79	2.48	0.41	864

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Oil burned, 5,350,000 bbl/yr, 9,200 Btu/kWh.
- Sulfur removed, 15,330 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $25,552,000; total depreciable investment, $48,212,000; and total capital investment, $49,199,000.
- All tons shown are 2,000 lb.

TABLE A-30

ROCKWELL INTERNATIONAL CLOSED-LOOP AQUEOUS CARBONATE PROCESS VARIATION FROM BASE CASE: OIL FIRED, EXISTING, REGULATED CO. ECONOMI

TOTAL CAPITAL INVESTMENT 49199000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR ELEMENTAL SULFUR	NET REVENUE, $/TON ELEMENTAL SULFUR	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1										
2										
3										
4										
5										
6	7000	32200000	5324100	15300	16000	36.00	18381900	576000	17805900	17805900
7	7000	32200000	5324100	15300	16000	36.00	18050200	576000	17474200	35280100
8	7000	32200000	5324100	15300	16000	36.00	17718500	576000	17142500	52422600
9	7000	32200000	5324100	15300	16000	36.00	17386800	576000	16810800	69233400
10	7000	32200000	5324100	15300	16000	36.00	17055100	576000	16479100	85712500
11	5000	23000000	3802900	11000	11400	36.00	15270400	410400	14860000	100572500
12	5000	23000000	3802900	11000	11400	36.00	14938700	410400	14528300	115100800
13	5000	23000000	3802900	11000	11400	36.00	14607000	410400	14196600	129297400
14	5000	23000000	3802900	11000	11400	36.00	14275300	410400	13864900	143162300
15	5000	23000000	3802900	11000	11400	36.00	13943600	410400	13533200	156695500
16	3500	16100000	2662000	7700	8000	36.00	12445600	288000	12157600	168853100
17	3500	16100000	2662000	7700	8000	36.00	12113900	288000	11825900	180679000
18	3500	16100000	2662000	7700	8000	36.00	11782200	288000	11494200	192173200
19	3500	16100000	2662000	7700	8000	36.00	11450500	288000	11162500	203335700
20	3500	16100000	2662000	7700	8000	36.00	11118800	288000	10830800	214166500
21	1500	6900000	1140900	3300	3400	36.00	9029300	122400	8906900	223073400
22	1500	6900000	1140900	3300	3400	36.00	8697600	122400	8575200	231648600
23	1500	6900000	1140900	3300	3400	36.00	8365900	122400	8243500	239892100
24	1500	6900000	1140900	3300	3400	36.00	8034200	122400	7911800	247803900
25	1500	6900000	1140900	3300	3400	36.00	7702500	122400	7580100	255384000
26	1500	6900000	1140900	3300	3400	36.00	7370800	122400	7248400	262632400
27	1500	6900000	1140900	3300	3400	36.00	7039100	122400	6916700	269549100
28	1500	6900000	1140900	3300	3400	36.00	6707400	122400	6585000	276134100
29	1500	6900000	1140900	3300	3400	36.00	6375700	122400	6253300	282387400
30	1500	6900000	1140900	3300	3400	36.00	6044000	122400	5921600	288309000
TOT	92500	425500000	70354000	203000	211000		295905000	7596000	288309000	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER BARREL OF OIL BURNED	4.21	0.11	4.10
MILLS PER KILOWATT-HOUR	6.40	0.17	6.23
CENTS PER MILLION BTU HEAT INPUT	69.54	1.78	67.76
DOLLARS PER TON OF SULFUR REMOVED	1457.66	37.42	1420.24

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 118719800 3445700 115274100

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER BARREL OF OIL BURNED	3.72	0.10	3.62
MILLS PER KILOWATT-HOUR	5.66	0.16	5.50
CENTS PER MILLION BTU HEAT INPUT	61.57	1.78	59.79
DOLLARS PER TON OF SULFUR REMOVED	1293.24	37.53	1255.71

TABLE A-31. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	305,000	1.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	1,952,000	11.2
SO_2 absorption (two absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	,902,000	10.9
Stack gas reheat (two indirect steam reheaters)	504,000	2.9
Chloride purge (two chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	2,153,000	12.4
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,534,000	8.8
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,464,000	25.6
Acid production (complete contact unit for sulfuric acid production)	3,063,000	17.6
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	520,000	3.0
Subtotal	16,397,000	94.2
Services, utilities, and miscellaneous	984,000	5.6
Total excluding pond	17,381,000	99.8
Pond	31,000	0.2
Total direct investment	17,412,000	100.0
Indirect Investment		
Engineering design and supervision	1,523,000	8.7
Architect and engineering contractor	380,000	2.3
Construction expense	2,681,000	15.4
Contractor fees	842,000	4.8
Total indirect investment	5,426,000	31.2
Contingency	4,568,000	26.2
Total fixed investment	27,406,000	157.4
Other Capital Charges		
Allowance for startup and modifications	2,737,000	15.7
Interest during construction	3,289,000	18.9
Total depreciable investment	33,432,000	192.0
Land	15,000	0.1
Working capital	760,000	4.4
Total capital investment	34,207,000	196.5

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-32. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,660 tons	103.00/ton	274,000	2.84
Catalyst	760 liters	2.50/liter	1,900	0.02
Agricultural limestone	1,370 tons	15.00/ton	20,600	0.21
Filter aid	30 tons	189.00/ton	5,700	0.06
Total raw materials cost			302,200	3.13
Conversion costs				
Operating labor and supervision	30,040 man-hr	12.50/man-hr	375,500	3.89
Utilities				
Steam	657,300 MBtu	2.00/MBtu	1,314,600	13.60
Process water	2,150,000 kgal	0.12/kgal	258,000	2.67
Electricity	33,012,000 kWh	0.031/kWh	1,023,400	10.59
Heat credit	20,400 MBtu	2.00/MBtu	(40,800)	(0.42)
Maintenance				
Labor and material			1,217,600	12.61
Analyses	4,480 man-hr	17.00/man-hr	76,200	0.79
Total conversion costs			4,224,500	43.73
Total direct costs			4,526,700	46.86
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			2,340,200	24.23
Average cost of capital and taxes at 8.6% of total capital investment			2,941,800	30.45
Overheads				
Plant, 50% of conversion costs less utilities			834,700	8.64
Administrative, 10% of operating labor			37,600	0.39
Marketing, 10% of byproduct sales revenue			113,500	1.18
Total indirect costs			6,267,800	64.89
Gross average annual revenue requirements			10,794,500	111.75
Byproduct Sales Revenue				
100% sulfuric acid	42,300 tons	25.00/ton 100% H_2SO_4	(1,057,500)	(10.95)
Sodium sulfate	3,380 tons	23.00/ton	(77,700)	(0.80)
Net average annual revenue requirements			9,659,300	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.90	15.25	0.73	658

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 20 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 14,680 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $17,412,000; total depreciable investment, $33,432,000; and total capital investment, $34,207,000.
- All tons shown are 2,000 lb.

TABEL A-33

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 200 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 34207000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NA2SO4	NET REVENUE, $/TON 100% H2SO4	NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11	5000	9500000	452400	10500	30200	2400	22.50	20.70	12904200	729200	12175000	12175000
12	5000	9500000	452400	10500	30200	2400	22.50	20.70	12616700	729200	11887500	24062500
13	5000	9500000	452400	10500	30200	2400	22.50	20.70	12329200	729200	11600000	35662500
14	5000	9500000	452400	10500	30200	2400	22.50	20.70	12041700	729200	11312500	46975000
15	5000	9500000	452400	10500	30200	2400	22.50	20.70	11754100	729200	11024900	57999900
16	3500	6650000	316700	7300	21200	1700	22.50	20.70	10459300	512200	9947100	67947000
17	3500	6650000	316700	7300	21200	1700	22.50	20.70	10171800	512200	9659600	77606600
18	3500	6650000	316700	7300	21200	1700	22.50	20.70	9884300	512200	9372100	86978700
19	3500	6650000	316700	7300	21200	1700	22.50	20.70	9596800	512200	9084600	96063300
20	3500	6650000	316700	7300	21200	1700	22.50	20.70	9309300	512200	8797100	104860400
21	1500	2850000	135700	3100	9100	700	22.50	20.70	7545800	219300	7326500	112186900
22	1500	2850000	135700	3100	9100	700	22.50	20.70	7258200	219300	7038900	119225800
23	1500	2850000	135700	3100	9100	700	22.50	20.70	6970700	219300	6751400	125977200
24	1500	2850000	135700	3100	9100	700	22.50	20.70	6683200	219300	6463900	132441100
25	1500	2850000	135700	3100	9100	700	22.50	20.70	6395700	219300	6176400	138617500
26	1500	2850000	135700	3100	9100	700	22.50	20.70	6108200	219300	5888900	144506400
27	1500	2850000	135700	3100	9100	700	22.50	20.70	5820700	219300	5601400	150107800
28	1500	2850000	135700	3100	9100	700	22.50	20.70	5533100	219300	5313800	155421600
29	1500	2850000	135700	3100	9100	700	22.50	20.70	5245600	219300	5026300	160447900
30	1500	2850000	135700	3100	9100	700	22.50	20.70	4958100	219300	4738800	165186700
TOT	57500	109250000	5202500	120000	348000	27500			173586700	8400000	165186700	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	33.37	1.62	31.75
MILLS PER KILOWATT-HOUR	15.09	0.73	14.36
CENTS PER MILLION BTU HEAT INPUT	158.89	7.69	151.20
DOLLARS PER TON OF SULFUR REMOVED	1446.56	70.00	1376.56
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	78509500	4152500	74357000

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	30.51	1.61	28.90
MILLS PER KILOWATT-HOUR	13.80	0.73	13.07
CENTS PER MILLION BTU HEAT INPUT	145.29	7.68	137.61
DOLLARS PER TON OF SULFUR REMOVED	1319.49	69.79	1249.70

TABLE A-34. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	301,000	1.8
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	1,908,000	11.2
SO_2 absorption (two absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	1,858,000	10.9
Stack gas reheat (two indirect steam reheaters)	493,000	2.9
Chloride purge (two chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	2,104,000	12.3
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,503,000	8.8
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,366,000	25.6
Acid production (complete contact unit for sulfuric acid production)	2,996,000	17.6
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	509,000	3.0
Subtotal	16,038,000	94.1
Services, utilities, and miscellaneous	962,000	5.6
Total excluding pond	17,000,000	99.7
Pond	56,000	0.3
Total direct investment	17,056,000	100.0
Indirect Investment		
Engineering design and supervision	1,522,000	8.9
Architect and engineering contractor	379,000	2.2
Construction expense	2,637,000	15.5
Contractor fees	829,000	4.9
Total indirect investment	5,367,000	31.5
Contingency	4,485,000	26.3
Total fixed investment	26,908,000	157.8
Other Capital Charges		
Allowance for startup and modifications	2,685,000	15.7
Interest during construction	3,229,000	18.9
Total depreciable investment	32,822,000	192.4
Land	15,000	0.1
Working capital	741,000	4.3
Total capital investment	33,578,000	196.8

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-35. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW new)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,580 tons	103.00/ton	265,700	2.91
Catalyst	740 liters	2.50/liter	1,900	0.02
Agricultural limestone	1,330 tons	15.00/ton	20,000	0.22
Filter aid	29 tons	189.00/ton	5,500	0.06
Total raw materials cost			293,100	3.21
Conversion costs				
Operating labor and supervision	30,040 man-hr	12.50/man-hr	375,500	4.11
Utilities				
Steam	636,500 MBtu	2.00/MBtu	1,273,000	13.93
Process water	2,082,300 kgal	0.12/kgal	249,900	2.73
Electricity	31,991,000 kWh	0.031/kWh	991,700	10.85
Heat credit	19,800 MBtu	2.00/MBtu	(39,600)	(0.43)
Maintenance				
Labor and material			1,191,700	3.04
Analyses	4,480 man-hr	17.00/man-hr	76,200	0.83
Total conversion costs			4,118,400	45.06
Total direct costs			4,411,500	48.27
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			1,969,300	21.55
Average cost of capital and taxes at 8.6% of total capital investment			2,887,700	31.59
Overheads				
Plant, 50% of conversion costs less utilities			821,700	8.99
Administrative, 10% of operating labor			37,600	0.41
Marketing, 10% of byproduct sales revenue			109,800	1.20
Total indirect costs			5,826,100	63.74
Gross average annual revenue requirements			10,237,600	112.01
Byproduct Sales Revenue				
100% sulfuric acid	40,900 tons	25.00/ton 100% H_2SO_4	(1,022,500)	(11.19)
Sodium sulfate	3,270 tons	23.00/ton	(75,200)	(0.82)
Net average annual revenue requirements			9,139,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.53	14.91	0.71	643

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 613,200 tons/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 14,220 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $17,056,000 ; total depreciable investment, $32,822,000; and total capital investment, $33,578,000.
- All tons shown are 2,000 lb.

TABLE A-36

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 200 MW, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 33578000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4	NET REVENUE, $/TON 100% H2SO4	NET REVENUE, $/TON NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14200	40900	3300	22.50	20.70	13015700	988600	12027100	12027100
2	7000	12880000	613300	14200	40900	3300	22.50	20.70	12827500	988600	11838900	23866000
3	7000	12880000	613300	14200	40900	3300	22.50	20.70	12639300	988600	11650700	35516700
4	7000	12880000	613300	14200	40900	3300	22.50	20.70	12451200	988600	11462600	46979300
5	7000	12880000	613300	14200	40900	3300	22.50	20.70	12263000	988600	11274400	58253700
6	7000	12880000	613300	14200	40900	3300	22.50	20.70	12074800	988600	11086200	69339900
7	7000	12880000	613300	14200	40900	3300	22.50	20.70	11886600	988600	10898000	80237900
8	7000	12880000	613300	14200	40900	3300	22.50	20.70	11698400	988600	10709800	90947700
9	7000	12880000	613300	14200	40900	3300	22.50	20.70	11510200	988600	10521600	101469300
10	7000	12880000	613300	14200	40900	3300	22.50	20.70	11322000	988600	10333400	111802700
11	5000	9200000	438100	10200	29200	2300	22.50	20.70	9890400	704600	9185800	120988500
12	5000	9200000	438100	10200	29200	2300	22.50	20.70	9702200	704600	8997600	129986100
13	5000	9200000	438100	10200	29200	2300	22.50	20.70	9514000	704600	8809400	138795500
14	5000	9200000	438100	10200	29200	2300	22.50	20.70	9325800	704600	8621200	147416700
15	5000	9200000	438100	10200	29200	2300	22.50	20.70	9137600	704600	8433000	155849700
16	3500	6440000	306700	7100	20500	1600	22.50	20.70	7967500	494400	7473100	163322800
17	3500	6440000	306700	7100	20500	1600	22.50	20.70	7779400	494400	7285000	170607800
18	3500	6440000	306700	7100	20500	1600	22.50	20.70	7591200	494400	7096800	177704600
19	3500	6440000	306700	7100	20500	1600	22.50	20.70	7403000	494400	6908600	184613200
20	3500	6440000	306700	7100	20500	1600	22.50	20.70	7214800	494400	6720400	191333600
21	1500	2760000	131400	3000	8800	700	22.50	20.70	5586300	212500	5373800	196707400
22	1500	2760000	131400	3000	8800	700	22.50	20.70	5398100	212500	5185600	201893000
23	1500	2760000	131400	3000	8800	700	22.50	20.70	5209900	212500	4997400	206890400
24	1500	2760000	131400	3000	8800	700	22.50	20.70	5021800	212500	4809300	211699700
25	1500	2760000	131400	3000	8800	700	22.50	20.70	4833600	212500	4621100	216320800
26	1500	2760000	131400	3000	8800	700	22.50	20.70	4645400	212500	4432900	220753700
27	1500	2760000	131400	3000	8800	700	22.50	20.70	4457200	212500	4244700	224998400
28	1500	2760000	131400	3000	8800	700	22.50	20.70	4269000	212500	4056500	229054900
29	1500	2760000	131400	3000	8800	700	22.50	20.70	4080800	212500	3868300	232923200
30	1500	2760000	131400	3000	8800	700	22.50	20.70	3892600	212500	3680100	236603300
TOT	127500	234600000	11171000	258500	745500	59500			254609300	18006000	236603300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	22.79	1.61	21.18
MILLS PER KILOWATT-HOUR	9.98	0.70	9.28
CENTS PER MILLION BTU HEAT INPUT	108.53	7.68	100.85
DOLLARS PER TON OF SULFUR REMOVED	984.95	69.66	915.29
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	90960500	7017400	83943100

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	20.89	1.61	19.28
MILLS PER KILOWATT-HOUR	9.15	0.70	8.45
CENTS PER MILLION BTU HEAT INPUT	99.47	7.67	91.80
DOLLARS PER TON OF SULFUR REMOVED	902.39	69.62	832.77

TABLE A-37. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 500 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	463,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,442,000	12.6
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,426,000	12.6
Stack gas reheat (four indirect steam reheaters)	1,153,000	3.3
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,977,000	14.2
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,678,000	7.6
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,283,000	23.6
Acid production (complete contact unit for sulfuric acid production)	5,684,000	16.2
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	908,000	2.6
Subtotal	33,014,000	94.0
Services, utilities, and miscellaneous	1,981,000	5.6
Total excluding pond	34,995,000	99.6
Pond	123,000	0.4
Total direct investment	35,118,000	100.0
Indirect Investment		
Engineering design and supervision	2,236,000	6.4
Architect and engineering contractor	556,000	1.6
Construction expense	4,803,000	13.6
Contractor fees	1,435,000	4.1
Total indirect investment	9,030,000	25.7
Contingency	8,830,000	25.1
Total fixed investment	52,978,000	150.8
Other Capital Charges		
Allowance for startup and modifications	5,286,000	15.1
Interest during construction	6,357,000	18.1
Total depreciable investment	64,621,000	184.0
Land	39,000	0.1
Working capital	1,567,000	4.5
Total capital investment	66,227,000	188.6

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-38. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 500 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,440 tons	103.00/ton	663,300	3.61
Catalyst	1,840 liters	2.50/liter	4,600	0.02
Agricultural limestone	3,310 tons	15.00/ton	49,700	0.27
Filter aid	72 tons	189.00/ton	13,600	0.07
Total raw materials cost			731,200	3.97
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	3.22
Utilities				
Steam	1,591,200 MBtu	2.00/MBtu	3,182,400	17.29
Process water	5,205,600 kgal	0.12/kgal	624,700	3.39
Electricity	79,074,000 kWh	0.029/kWh	2,293,100	12.46
Heat credit	49,500 MBtu	2.00/MBtu	(99,000)	(0.54)
Maintenance				
Labor and material			2,103,400	11.42
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.78
Total conversion costs			8,842,900	48.02
Total direct costs			9,574,100	51.99
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			4,135,700	22.46
Average cost of capital and taxes at 8.6% of total capital investment			5,695,500	30.93
Overheads				
Plant, 50% of conversion costs less utilities			1,420,900	7.72
Administrative, 10% of operating labor			59,400	0.32
Marketing, 10% of byproduct sales revenue			274,600	1.49
Total indirect costs			11,586,100	62.92
Gross average annual revenue requirements			21,160,200	114.91
Byproduct Sales Revenue				
100% sulfuric acid	102,300 tons	25.00/ton 100% H_2SO_4	(2,557,500)	(13.89)
Sodium sulfate	8,180 tons	23.00/ton	(188,100)	(1.02)
Net average annual revenue requirements			18,414,600	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.26	12.01	0.57	518

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 35,550 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $35,118,000; total depreciable investment, $64,621,000; and total capital investment, $66,227,000.
- All tons shown are 2,000 lb.

TABLE A-39

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 500 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 66227000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4	NET REVENUE, $/TON 100% H2SO4	NET REVENUE, $/TON NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	32200000	1533300	35600	102300	8200	22.50	20.70	27012100	2471500	24540600	24540600
7	7000	32200000	1533300	35600	102300	8200	22.50	20.70	26567600	2471500	24096100	48636700
8	7000	32200000	1533300	35600	102300	8200	22.50	20.70	26123000	2471500	23651500	72288200
9	7000	32200000	1533300	35600	102300	8200	22.50	20.70	25678400	2471500	23206900	95495100
10	7000	32200000	1533300	35600	102300	8200	22.50	20.70	25233800	2471500	22762300	118257400
11	5000	23000000	1095200	25400	73100	5800	22.50	20.70	22079800	1764900	20314900	138572300
12	5000	23000000	1095200	25400	73100	5800	22.50	20.70	21635200	1764900	19870300	158442600
13	5000	23000000	1095200	25400	73100	5800	22.50	20.70	21190600	1764900	19425700	177868300
14	5000	23000000	1095200	25400	73100	5800	22.50	20.70	20746100	1764900	18981200	196849500
15	5000	23000000	1095200	25400	73100	5800	22.50	20.70	20301500	1764900	18536600	215386100
16	3500	16100000	766700	17800	51100	4100	22.50	20.70	17739800	1234700	16505100	231891200
17	3500	16100000	766700	17800	51100	4100	22.50	20.70	17295200	1234700	16060500	247951700
18	3500	16100000	766700	17800	51100	4100	22.50	20.70	16850600	1234700	15615900	263567600
19	3500	16100000	766700	17800	51100	4100	22.50	20.70	16406000	1234700	15171300	278738900
20	3500	16100000	766700	17800	51100	4100	22.50	20.70	15961400	1234700	14726700	293465600
21	1500	6900000	328600	7600	21900	1800	22.50	20.70	12470000	530100	11939900	305405500
22	1500	6900000	328600	7600	21900	1800	22.50	20.70	12025400	530100	11495300	316900800
23	1500	6900000	328600	7600	21900	1800	22.50	20.70	11580800	530100	11050700	327951500
24	1500	6900000	328600	7600	21900	1800	22.50	20.70	11136200	530100	10606100	338557600
25	1500	6900000	328600	7600	21900	1800	22.50	20.70	10691600	530100	10161500	348719100
26	1500	6900000	328600	7600	21900	1800	22.50	20.70	10247000	530100	9716900	358436000
27	1500	6900000	328600	7600	21900	1800	22.50	20.70	9802400	530100	9272300	367708300
28	1500	6900000	328600	7600	21900	1800	22.50	20.70	9357900	530100	8827800	376536100
29	1500	6900000	328600	7600	21900	1800	22.50	20.70	8913300	530100	8383200	384919300
30	1500	6900000	328600	7600	21900	1800	22.50	20.70	8468700	530100	7938600	392857900
TOT	92500	425500000	20262000	470000	1351500	108500			425514400	32656500	392857900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	21.00	1.61	19.39
MILLS PER KILOWATT-HOUR	9.20	0.71	8.49
CENTS PER MILLION BTU HEAT INPUT	100.00	7.67	92.33
DOLLARS PER TON OF SULFUR REMOVED	905.35	69.48	835.87

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 172852700 14797100 158055600

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	18.83	1.61	17.22
MILLS PER KILOWATT-HOUR	8.25	0.71	7.54
CENTS PER MILLION BTU HEAT INPUT	89.65	7.67	81.98
DOLLARS PER TON OF SULFUR REMOVED	811.13	69.43	741.70

TABLE A-40. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 2.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	318,000	1.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	16.3
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	16.2
Stack gas reheat (four indirect steam reheaters)	1,136,000	4.2
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	18.2
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,619,000	6.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,742,000	17.6
Acid production (complete contact unit for sulfuric acid production)	3,254,000	12.1
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	549,000	2.0
Subtotal	25,240,000	93.8
Services, utilities, and miscellaneous	1,514,000	5.6
Total excluding pond	26,754,000	99.4
Pond	154,000	0.6
Total direct investment	26,908,000	100.0
Indirect Investment		
Engineering design and supervision	2,069,000	7.7
Architect and engineering contractor	514,000	1.9
Construction expense	3,853,000	14.3
Contractor fees	1,172,000	4.4
Total indirect investment	7,608,000	28.3
Contingency	6,903,000	25.6
Total fixed investment	41,419,000	153.9
Other Capital Charges		
Allowance for startup and modifications	4,127,000	15.3
Interest during construction	4,970,000	18.5
Total depreciable investment	50,516,000	187.7
Land	42,000	0.2
Working capital	1,075,000	4.0
Total capital investment	51,633,000	191.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-41. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 2.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,900 tons	103.00/ton	298,700	2.12
Catalyst	830 liters	2.50/liter	2,100	0.01
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.35
Filter aid	32 tons	189.00/ton	6,000	0.04
Total raw materials cost			355,400	2.52
Conversion costs				
Operating labor and supervision	42,550 man-hr	12.50/man-hr	531,900	3.78
Utilities				
Steam	942,600 MBtu	2.00/MBtu	1,885,200	13.40
Process water	2,445,700 kgal	0.12/kgal	293,500	2.09
Electricity	60,803,000 kWh	0.029/kWh	1,763,300	12.53
Heat credit	22,300 MBtu	2.00/MBtu	(44,600)	(0.32)
Maintenance				
Labor and material			1,609,900	11.44
Analyses	7,610 man-hr	17.00/man-hr	129,400	0.92
Total conversion costs			6,168,600	43.84
Total direct costs			6,524,000	46.36
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,031,000	21.54
Average cost of capital and taxes at 8.6% of total capital investment			4,440,400	31.56
Overheads				
Plant, 50% of conversion costs less utilities			1,135,600	8.07
Administrative, 10% of operating labor			53,200	0.38
Marketing, 10% of byproduct sales revenue			123,700	0.88
Total indirect costs			8,783,900	62.43
Gross average annual revenue requirements			15,307,900	108.79
Byproduct Sales Revenue				
100% sulfuric acid	46,100 tons	25.00/ton 100% H_2SO_4	(1,152,500)	(8.19)
Sodium sulfate	3,680 tons	23.00/ton	(84,600)	(0.60)
Net average annual revenue requirements			14,070,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.02	9.38	0.45	879

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 16,000 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $26,908,000; total depreciable investment, $50,516,000; and total capital investment, $51,633,000.
- All tons shown are 2,000 lb.

TABLE A-42

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 2.0% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 51633000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/YR	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4	NET REVENUE, $/TON 100% H2SO4	NET REVENUE, $/TON NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	16000	46100	3700	22.50	20.70	19624900	1113900	18511000	18511000
2	7000	31500000	1500000	16000	46100	3700	22.50	20.70	19335200	1113900	18221300	36732300
3	7000	31500000	1500000	16000	46100	3700	22.50	20.70	19045600	1113900	17931700	54664000
4	7000	31500000	1500000	16000	46100	3700	22.50	20.70	18756000	1113900	17642100	72306100
5	7000	31500000	1500000	16000	46100	3700	22.50	20.70	18466400	1113900	17352500	89658600
6	7000	31500000	1500000	16000	46100	3700	22.50	20.70	18176700	1113900	17062800	106721400
7	7000	31500000	1500000	16000	46100	3700	22.50	20.70	17887100	1113900	16773200	123494600
8	7000	31500000	1500000	16000	46100	3700	22.50	20.70	17597500	1113900	16483600	139978200
9	7000	31500000	1500000	16000	46100	3700	22.50	20.70	17307800	1113900	16193900	156172100
10	7000	31500000	1500000	16000	46100	3700	22.50	20.70	17018200	1113900	15904300	172076400
11	5000	22500000	1071400	11400	32900	2600	22.50	20.70	14884900	794100	14090800	186167200
12	5000	22500000	1071400	11400	32900	2600	22.50	20.70	14595200	794100	13801100	199968300
13	5000	22500000	1071400	11400	32900	2600	22.50	20.70	14305600	794100	13511500	213479800
14	5000	22500000	1071400	11400	32900	2600	22.50	20.70	14016000	794100	13221900	226701700
15	5000	22500000	1071400	11400	32900	2600	22.50	20.70	13726300	794100	12932200	239633900
16	3500	15750000	750000	8000	23100	1800	22.50	20.70	11986000	557100	11428900	251062800
17	3500	15750000	750000	8000	23100	1800	22.50	20.70	11696400	557100	11139300	262202100
18	3500	15750000	750000	8000	23100	1800	22.50	20.70	11406800	557100	10849700	273051800
19	3500	15750000	750000	8000	23100	1800	22.50	20.70	11117100	557100	10560000	283611800
20	3500	15750000	750000	8000	23100	1800	22.50	20.70	10827500	557100	10270400	293882200
21	1500	6750000	321400	3400	9900	800	22.50	20.70	8424400	239400	8185000	302067200
22	1500	6750000	321400	3400	9900	800	22.50	20.70	8134700	239400	7895300	309962500
23	1500	6750000	321400	3400	9900	800	22.50	20.70	7845100	239400	7605700	317568200
24	1500	6750000	321400	3400	9900	800	22.50	20.70	7555500	239400	7316100	324884300
25	1500	6750000	321400	3400	9900	800	22.50	20.70	7265800	239400	7026400	331910700
26	1500	6750000	321400	3400	9900	800	22.50	20.70	6976200	239400	6736800	338647500
27	1500	6750000	321400	3400	9900	800	22.50	20.70	6686600	239400	6447200	345094700
28	1500	6750000	321400	3400	9900	800	22.50	20.70	6396900	239400	6157500	351252200
29	1500	6750000	321400	3400	9900	800	22.50	20.70	6107300	239400	5867900	357120100
30	1500	6750000	321400	3400	9900	800	22.50	20.70	5817700	239400	5578300	362698400
TOT	127500	573750000	27321000	291000	840000	67000			382987400	20289000	362698400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	14.02	0.74	13.28
MILLS PER KILOWATT-HOUR	6.01	0.32	5.69
CENTS PER MILLION BTU HEAT INPUT	66.75	3.53	63.22
DOLLARS PER TON OF SULFUR REMOVED	1316.11	69.72	1246.39
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	136941100	7907100	129034000

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	12.86	0.74	12.12
MILLS PER KILOWATT-HOUR	5.51	0.32	5.19
CENTS PER MILLION BTU HEAT INPUT	61.23	3.53	57.70
DOLLARS PER TON OF SULFUR REMOVED	1206.53	69.67	1136.86

TABLE A-43. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Base case: 500 MW, 3.5% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	12.6
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	12.6
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.3
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	14.1
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	7.6
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,161,000	23.6
Acid production (complete contact unit for sulfuric acid production)	5,600,000	16.2
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	895,000	2.6
Subtotal	32,513,000	93.9
Services, utilities, and miscellaneous	1,951,000	5.6
Total excluding pond	34,464,000	99.5
Pond	154,000	0.5
Total direct investment	34,618,000	100.0
Indirect Investment		
Engineering design and supervision	2,233,000	6.4
Architect and engineering contractor	555,000	1.6
Construction expense	4,748,000	13.7
Contractor fees	1,420,000	4.1
Total indirect investment	8,956,000	25.8
Contingency	8,715,000	25.2
Total fixed investment	52,289,000	151.0
Other Capital Charges		
Allowance for startup and modifications	5,214,000	15.1
Interest during construction	6,275,000	18.1
Total depreciable investment	63,778,000	184.2
Land	42,000	0.1
Working capital	1,540,000	4.4
Total capital investment	65,360,000	188.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-44. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Base case: 500 MW, 3.5% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	3.63
Catalyst	1,800 liters	2.50/liter	4,500	0.03
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.27
Filter aid	70 tons	189.00/ton	13,200	0.07
Total raw materials cost			715,200	4.00
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	3.32
Utilities				
Steam	1,556,600 MBtu	2.00/MBtu	3,113,200	17.40
Process water	5,092,500 kgal	0.12/kgal	611,100	3.42
Electricity	77,369,900 kWh	0.029/kWh	2,243,700	12.54
Heat credit	48,400 MBtu	2.00/MBtu	(96,800)	(0.54)
Maintenance				
Labor and material			2,072,500	11.58
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.81
Total conversion costs			8,682,000	48.53
Total direct costs			9,397,200	52.53
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,826,700	21.39
Average cost of capital and taxes at 8.6% of total capital investment			5,621,000	31.42
Overheads				
Plant, 50% of conversion costs less utilities			1,405,400	7.85
Administrative, 10% of operating labor			59,400	0.33
Marketing, 10% of byproduct sales revenue			268,700	1.50
Total indirect costs			11,181,200	62.49
Gross average annual revenue requirements			20,578,400	115.02
Byproduct Sales Revenue				
100% sulfuric acid	100,100 tons	25.00/ton 100% H_2SO_4	(2,502,500)	(13.99)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(1.03)
Net average annual revenue requirements			17,891,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.11	11.93	0.57	514

Basis
- Midwest plant [illegible] ation, 1980 revenue requirements.
- Remaining life [illegible] power plant, 30 yr.
- Power unit on-s[illegible] m time, 7,000 hr/yr.
- Coal burned, 1,50[illegible],100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat t[illegible] 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $34,618,000; total depreciable investment, $63,778,000; and total capital investment, $65,360,000.
- All tons shown are 2,000 lb.

TABLE A-45

WELLMAN-LORD/ SULFURIC ACID PROCESS BASE CASE: 500 MW 3.5% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 65360000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4	NET REVENUE, $/TON 100% H2SO4	NET REVENUE, $/TON NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	100100	8000	22.50	20.70	25930800	2417900	23512900	23512900
2	7000	31500000	1500000	34800	100100	8000	22.50	20.70	25565200	2417900	23147300	46660200
3	7000	31500000	1500000	34800	100100	8000	22.50	20.70	25199500	2417900	22781600	69441800
4	7000	31500000	1500000	34800	100100	8000	22.50	20.70	24833900	2417900	22416000	91857800
5	7000	31500000	1500000	34800	100100	8000	22.50	20.70	24468200	2417900	22050300	113908100
6	7000	31500000	1500000	34800	100100	8000	22.50	20.70	24102500	2417900	21684600	135592700
7	7000	31500000	1500000	34800	100100	8000	22.50	20.70	23736900	2417900	21319000	156911700
8	7000	31500000	1500000	34800	100100	8000	22.50	20.70	23371200	2417900	20953300	177865000
9	7000	31500000	1500000	34800	100100	8000	22.50	20.70	23005600	2417900	20587700	198452700
10	7000	31500000	1500000	34800	100100	8000	22.50	20.70	22639900	2417900	20222000	218674700
11	5000	22500000	1071400	24800	71500	5700	22.50	20.70	19615100	1726800	17888300	236563000
12	5000	22500000	1071400	24800	71500	5700	22.50	20.70	19249400	1726800	17522600	254085600
13	5000	22500000	1071400	24800	71500	5700	22.50	20.70	18883800	1726800	17157000	271242600
14	5000	22500000	1071400	24800	71500	5700	22.50	20.70	18518100	1726800	16791300	288033900
15	5000	22500000	1071400	24800	71500	5700	22.50	20.70	18152500	1726800	16425700	304459600
16	3500	15750000	750000	17400	50100	4000	22.50	20.70	15708500	1210100	14498400	318958000
17	3500	15750000	750000	17400	50100	4000	22.50	20.70	15342800	1210100	14132700	333090700
18	3500	15750000	750000	17400	50100	4000	22.50	20.70	14977200	1210100	13767100	346857800
19	3500	15750000	750000	17400	50100	4000	22.50	20.70	14611500	1210100	13401400	360259200
20	3500	15750000	750000	17400	50100	4000	22.50	20.70	14245900	1210100	13035800	373295000
21	1500	6750000	321400	7500	21500	1700	22.50	20.70	10887200	519000	10368200	383663200
22	1500	6750000	321400	7500	21500	1700	22.50	20.70	10521600	519000	10002600	393665800
23	1500	6750000	321400	7500	21500	1700	22.50	20.70	10155900	519000	9636900	403302700
24	1500	6750000	321400	7500	21500	1700	22.50	20.70	9790300	519000	9271300	412574000
25	1500	6750000	321400	7500	21500	1700	22.50	20.70	9424600	519000	8905600	421479600
26	1500	6750000	321400	7500	21500	1700	22.50	20.70	9059000	519000	8540000	430019600
27	1500	6750000	321400	7500	21500	1700	22.50	20.70	8693300	519000	8174300	438193900
28	1500	6750000	321400	7500	21500	1700	22.50	20.70	8327600	519000	7808600	446002500
29	1500	6750000	321400	7500	21500	1700	22.50	20.70	7962000	519000	7443000	453445500
30	1500	6750000	321400	7500	21500	1700	22.50	20.70	7596300	519000	7077300	460522800
TOT	127500	573750000	27321000	634000	1824000	145500			504576300	44053500	460522800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

MILLS PER KILOWATT-HOUR	7.91	0.69	7.22
CENTS PER MILLION BTU HEAT INPUT	87.94	7.67	80.27
DOLLARS PER TON OF SULFUR REMOVED	795.86	69.48	726.38
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	181084100	17167500	163916600

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

MILLS PER KILOWATT-HOUR	7.29	0.69	6.60
CENTS PER MILLION BTU HEAT INPUT	80.97	7.68	73.29
DOLLARS PER TON OF SULFUR REMOVED	733.13	69.50	663.63

TABLE A-46. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 5.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	561,000	1.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	10.7
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	10.5
Stack gas reheat (four indirect steam reheaters)	1,136,000	2.8
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	11.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	3,465,000	8.4
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	11,034,000	26.9
Acid production (complete contact unit for sulfuric acid production)	7,571,000	18.5
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	1,174,000	2.9
Subtotal	38,563,000	94.0
Services, utilities, and miscellaneous	2,314,000	5.6
Total excluding pond	40,877,000	99.6
Pond	154,000	0.4
Total direct investment	41,031,000	100.0
Indirect Investment		
Engineering design and supervision	2,371,000	5.8
Architect and engineering contractor	590,000	1.5
Construction expense	5,466,000	13.3
Contractor fees	1,615,000	3.9
Total indirect investment	10,042,000	24.5
Contingency	10,215,000	24.9
Total fixed investment	61,288,000	149.4
Other Capital Charges		
Allowance for startup and modifications	6,113,000	14.9
Interest during construction	7,354,000	17.9
Total depreciable investment	74,755,000	182.2
Land	42,000	0.1
Working capital	1,982,000	4.8
Total capital investment	76,779,000	187.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-47. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 5.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	9,690 tons	103.00/ton	998,100	4.70
Catalyst	2,770 liters	2.50/liter	6,900	0.03
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.23
Filter aid	108 tons	189.00/ton	20,400	0.10
Total raw materials cost			1,074,000	5.06
Conversion costs				
Operating labor and supervision	51,020 man-hr	12.50/man-hr	637,800	3.00
Utilities				
Steam	2,168,500 MBtu	2.00/MBtu	4,337,000	20.44
Process water	7,730,300 kgal	0.12/kgal	927,600	4.37
Electricity	93,882,000 kWh	0.029/kWh	2,722,600	12.83
Heat credit	74,400 MBtu	2.00/MBtu	(148,800)	(9.70)
Maintenance				
Labor and material			2,457,200	11.58
Analyses	9,130 man-hr	17.00/man-hr	155,200	0.73
Total conversion costs			11,088,600	52.25
Total direct costs			12,162,600	57.31
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,485,300	21.14
Average cost of capital and taxes at 8.6% of total capital investment			6,603,000	31.11
Overheads				
Plant, 50% of conversion costs less utilities			1,625,100	7.66
Administrative, 10% of operating labor			63,800	0.30
Marketing, 10% of byproduct sales revenue			413,300	1.95
Total indirect costs			13,190,500	62.16
Gross average annual revenue requirements			25,353,100	119.47
Byproduct Sales Revenue				
100% sulfuric acid	154,000 tons	25.00/ton 100% H_2SO_4	(3,850,000)	(18.14)
Sodium sulfate	12,300 tons	23.00/ton	(282,900)	(1.33)
Net average annual revenue requirements			21,220,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.06	14.15	0.67	397

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 53,500 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $41,031,000; total depreciable investment, $74,755,000; and total capital investment, $76,779,000.
- All tons shown are 2,000 lb.

TABLE A-48

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 5.0% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 76779000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4	NET REVENUE, $/TON 100% H2SO4	NET REVENUE, $/TON NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	53500	154000	12300	22.50	20.70	31543000	3719600	27823400	27823400
2	7000	31500000	1500000	53500	154000	12300	22.50	20.70	31114400	3719600	27394800	55218200
3	7000	31500000	1500000	53500	154000	12300	22.50	20.70	30685800	3719600	26966200	82184400
4	7000	31500000	1500000	53500	154000	12300	22.50	20.70	30257200	3719600	26537600	108722000
5	7000	31500000	1500000	53500	154000	12300	22.50	20.70	29828600	3719600	26109000	134831000
6	7000	31500000	1500000	53500	154000	12300	22.50	20.70	29400000	3719600	25680400	160511400
7	7000	31500000	1500000	53500	154000	12300	22.50	20.70	28971500	3719600	25251900	185763300
8	7000	31500000	1500000	53500	154000	12300	22.50	20.70	28542900	3719600	24823300	210586600
9	7000	31500000	1500000	53500	154000	12300	22.50	20.70	28114300	3719600	24394700	234981300
10	7000	31500000	1500000	53500	154000	12300	22.50	20.70	27685700	3719600	23966100	258947400
11	5000	22500000	1071400	38200	110000	8800	22.50	20.70	23812400	2657200	21155200	280102600
12	5000	22500000	1071400	38200	110000	8800	22.50	20.70	23383800	2657200	20726600	300829200
13	5000	22500000	1071400	38200	110000	8800	22.50	20.70	22955200	2657200	20298000	321127200
14	5000	22500000	1071400	38200	110000	8800	22.50	20.70	22526600	2657200	19869400	340996600
15	5000	22500000	1071400	38200	110000	8800	22.50	20.70	22098000	2657200	19440800	360437400
16	3500	15750000	750000	26800	77000	6100	22.50	20.70	18988600	1858800	17129800	377567200
17	3500	15750000	750000	26800	77000	6100	22.50	20.70	18560100	1858800	16701300	394268500
18	3500	15750000	750000	26800	77000	6100	22.50	20.70	18131500	1858800	16272700	410541200
19	3500	15750000	750000	26800	77000	6100	22.50	20.70	17702900	1858800	15844100	426385300
20	3500	15750000	750000	26800	77000	6100	22.50	20.70	17274300	1858800	15415500	441800800
21	1500	6750000	321400	11500	33000	2600	22.50	20.70	13014500	796300	12218200	454019000
22	1500	6750000	321400	11500	33000	2600	22.50	20.70	12585900	796300	11789600	465808600
23	1500	6750000	321400	11500	33000	2600	22.50	20.70	12157300	796300	11361000	477169600
24	1500	6750000	321400	11500	33000	2600	22.50	20.70	11728700	796300	10932400	488102000
25	1500	6750000	321400	11500	33000	2600	22.50	20.70	11300100	796300	10503800	498605800
26	1500	6750000	321400	11500	33000	2600	22.50	20.70	10871500	796300	10075200	508681000
27	1500	6750000	321400	11500	33000	2600	22.50	20.70	10443000	796300	9646700	518327700
28	1500	6750000	321400	11500	33000	2600	22.50	20.70	10014400	796300	9218100	527545800
29	1500	6750000	321400	11500	33000	2600	22.50	20.70	9585800	796300	8789500	536335300
30	1500	6750000	321400	11500	33000	2600	22.50	20.70	9157200	796300	8360900	544696200
TOT	127500	573750000	27321000	975000	2805000	223500			612435200	67739000	544696200	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	22.42	2.48	19.94
MILLS PER KILOWATT-HOUR	9.61	1.07	8.54
CENTS PER MILLION BTU HEAT INPUT	106.74	11.80	94.94
DOLLARS PER TON OF SULFUR REMOVED	628.14	69.48	558.66

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 220416200 26407400 194008800

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	20.70	2.48	18.22
MILLS PER KILOWATT-HOUR	8.87	1.06	7.81
CENTS PER MILLION BTU HEAT INPUT	98.56	11.81	86.75
DOLLARS PER TON OF SULFUR REMOVED	580.20	69.52	510.68

TABLE A-49. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	634,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	7,010,000	12.4
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	7,525,000	13.3
Stack gas reheat (four indirect steam reheaters)	1,846,000	3.3
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	8,232,000	14.6
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	4,088,000	7.2
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	13,262,000	23.6
Acid production (complete contact unit for sulfuric acid production)	9,100,000	16.2
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	1,385,000	2.5
Subtotal	53,082,000	94.2
Services, utilities, and miscellaneous	3,185,000	5.6
Total excluding pond	56,267,000	99.8
Pond	127,000	0.2
Total direct investment	56,394,000	100.0
Indirect Investment		
Engineering design and supervision	2,706,000	4.8
Architect and engineering contractor	674,000	1.2
Construction expense	7,114,000	12.6
Contractor fees	2,057,000	3.6
Total indirect investment	12,551,000	22.2
Contingency	13,789,000	24.5
Total fixed investment	82,734,000	146.7
Other Capital Charges		
Allowance for startup and modifications	8,261,000	14.6
Interest during construction	9,928,000	17.7
Total depreciable investment	100,923,000	179.0
Land	66,000	0.1
Working capital	2,702,000	4.8
Total capital investment	103,691,000	183.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-50. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	12,600 tons	103.00/ton	1,297,800	4.41
Catalyst	3,600 liters	2.50/liter	9,000	0.03
Agricultural limestone	6,480 tons	15.00/ton	97,200	0.33
Filter aid	140 tons	189.00/ton	26,500	0.09
Total raw materials cost			1,430,500	4.86
Conversion costs				
Operating labor and supervision	67,180 man-hr	12.50/man-hr	839,800	2.85
Utilities				
Steam	3,113,300 MBtu	2.00/MBtu	6,226,600	21.13
Process water	10,185,000 kgal	0.12/kgal	1,222,200	4.15
Electricity	154,140,000 kWh	0.028/kWh	4,315,900	14.65
Heat credit	96,800 MBtu	2.00/MBtu	(193,600)	(0.66)
Maintenance				
Labor and material			2,817,200	9.56
Analyses	13,810 man-hr	17.00/man-hr	234,800	0.80
Total conversion costs			15,462,900	52.48
Total direct costs			16,893,400	57.34
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			6,459,100	21.92
Average cost of capital and taxes at 8.6% of total capital investment			8,917,400	30.27
Overheads				
Plant, 50% of conversion costs less utilities			1,945,900	6.60
Administrative, 10% of operating labor			84,000	0.29
Marketing, 10% of byproduct sales revenue			537,300	1.82
Total indirect costs			17,943,700	60.90
Gross average annual revenue requirements			34,837,100	118.24
Byproduct Sales Revenue				
100% sulfuric acid	200,200 tons	25.00/ton 100% H_2SO_4	(5,005,000)	(16.99)
Sodium sulfate	16,000 tons	23.00/ton	(368,000)	(1.25)
Net average annual revenue requirements			29,464,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.21	9.82	0.47	424

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,999,900 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 69,560 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $56,394,000; total depreciable investment, $100,923,000; and total capital investment, $103,691,000.
- All tons shown are 2,000 lb.

TABLE A-51

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 1000MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 103691000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NA2SO4	NET REVENUE, $/TON 100% H2SO4	NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	63000000	3000000	69600	200200	16000	22.50	20.70	43890400	4835700	39054700	39054700
7	7000	63000000	3000000	69600	200200	16000	22.50	20.70	43196000	4835700	38360300	77415000
8	7000	63000000	3000000	69600	200200	16000	22.50	20.70	42501700	4835700	37666000	115081000
9	7000	63000000	3000000	69600	200200	16000	22.50	20.70	41807300	4835700	36971600	152052600
10	7000	63000000	3000000	69600	200200	16000	22.50	20.70	41113000	4835700	36277300	188329900
11	5000	45000000	2142900	49700	143000	11400	22.50	20.70	35622500	3453500	32169000	220498900
12	5000	45000000	2142900	49700	143000	1140.	22.50	20.70	34928200	3453500	31474700	251973600
13	5000	45000000	2142900	49700	143000	11400	22.50	20.70	34233800	3453500	30780300	282753900
14	5000	45000000	2142900	49700	143000	11400	22.50	20.70	33539500	3453500	30086000	312839900
15	5000	45000000	2142900	49700	143000	11400	22.50	20.70	32845100	3453500	29391600	342231500
16	3500	31500000	1500000	34800	100100	8000	22.50	20.70	28438500	2417900	26020600	368252100
17	3500	31500000	1500000	34800	100100	8000	22.50	20.70	27744100	2417900	25326200	393578300
18	3500	31500000	1500000	34800	100100	8000	22.50	20.70	27049800	2417900	24631900	418210200
19	3500	31500000	1500000	34800	100100	8000	22.50	20.70	26355400	2417900	23937500	442147700
20	3500	31500000	1500000	34800	100100	8000	22.50	20.70	25661100	2417900	23243200	465390900
21	1500	13500000	642900	14900	42900	3400	22.50	20.70	19712200	1035700	18676500	484067400
22	1500	13500000	642900	14900	42900	3400	22.50	20.70	19017800	1035700	17982100	502049500
23	1500	13500000	642900	14900	42900	3400	22.50	20.70	18323500	1035700	17287800	519337300
24	1500	13500000	642900	14900	42900	3400	22.50	20.70	17629100	1035700	16593400	535930700
25	1500	13500000	642900	14900	42900	3400	22.50	20.70	16934800	1035700	15899100	551829800
26	1500	13500000	642900	14900	42900	3400	22.50	20.70	16240400	1035700	15204700	567034500
27	1500	13500000	642900	14900	42900	3400	22.50	20.70	15546100	1035700	14510400	581544900
28	1500	13500000	642900	14900	42900	3400	22.50	20.70	14851700	1035700	13816000	595360900
29	1500	13500000	642900	14900	42900	3400	22.50	20.70	14157400	1035700	13121700	608482600
30	1500	13500000	642900	14900	42900	3400	22.50	20.70	13463000	1035700	12427300	620909900
TOT	92500	832500000	39643500	919500	2645500	211000			684802400	63892500	620909900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	17.27	1.61	15.66
MILLS PER KILOWATT-HOUR	7.40	0.69	6.71
CENTS PER MILLION BTU HEAT INPUT	82.26	7.68	74.58
DOLLARS PER TON OF SULFUR REMOVED	744.76	69.49	675.27

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 279706800 28953400 250753400

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	15.57	1.61	13.96
MILLS PER KILOWATT-HOUR	6.67	0.69	5.98
CENTS PER MILLION BTU HEAT INPUT	74.15	7.68	66.47
DOLLARS PER TON OF SULFUR REMOVED	671.24	69.48	601.76

TABLE A-52. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	624,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	6,853,000	12.4
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	7,324,000	13.3
Stack gas reheat (four indirect steam reheaters)	1,802,000	3.3
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	8,026,000	14.6
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	4,001,000	7.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	12,943,000	23.5
Acid production (complete contact unit for sulfuric acid production)	8,882,000	16.1
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	1,356,000	2.5
Subtotal	51,811,000	94.1
Services, utilities, and miscellaneous	3,109,000	5.6
Total excluding pond	54,920,000	99.7
Pond	159,000	0.3
Total direct investment	55,079,000	100.0
Indirect Investment		
Engineering design and supervision	2,694,000	4.9
Architect and engineering contractor	670,000	1.2
Construction expense	6,977,000	12.6
Contractor fees	2,020,000	3.7
Total indirect investment	12,361,000	22.4
Contingency	13,488,000	24.5
Total fixed investment	80,928,000	146.9
Other Capital Charges		
Allowance for startup and modifications	8,077,000	14.7
Interest during construction	9,711,000	17.6
Total depreciable investment	98,716,000	179.2
Land	69,000	0.1
Working capital	2,626,000	4.8
Total capital investment	101,411,000	184.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-53. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW new)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	12,200 tons	103.00/ton	1,256,600	4.43
Catalyst	3,480 liters	2.50/liter	8,700	0.03
Agricultural limestone	6,260 tons	15.00/ton	93,900	0.33
Filter aid	135 tons	189.00/ton	25,500	0.09
Total raw materials cost			1,384,700	4.88
Conversion costs				
Operating labor and supervision	67,180 man-hr	12.50/man-hr	839,800	2.96
Utilities				
Steam	3,009,400 MBtu	2.00/MBtu	6,018,800	21.22
Process water	9,845,300 kgal	0.12/kgal	1,181,400	4.17
Electricity	149,019,300 kWh	0.028/kWh	4,172,500	14.71
Heat credit	93,600 MBtu	2.00/MBtu	(187,200)	(0.66)
Maintenance				
Labor and material			2,750,800	9.70
Analyses	13,810 man-hr	17.00/man-hr	234,800	0.83
Total conversion costs			15,010,900	52.93
Total direct costs			16,395,600	57.81
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			5,923,000	20.88
Average cost of capital and taxes at 8.6% of total capital investment			8,721,300	30.75
Overheads				
Plant, 50% of conversion costs less utilities			1,912,700	6.74
Administrative, 10% of operating labor			84,000	0.30
Marketing, 10% of byproduct sales revenue			519,300	1.83
Total indirect costs			17,160,300	60.50
Gross average annual revenue requirements			33,555,900	118.31
Byproduct Sales Revenue				
100% sulfuric acid	193,500 tons	25.00/ton 100% H_2SO_4	(4,837,500)	(17.06)
Sodium sulfate	15,470 tons	23.00/ton	(355,800)	(1.25)
Net average annual revenue requirements			28,362,600	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.05	9.78	0.47	422

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 67,240 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $55,079,000 ; total depreciable investment, $98,716,000 ; and total capital investment, $101,411,000.
- All tons shown are 2,000 lb.

TABLE A-54

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 1000 MW, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 101411000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NA2SO4	NET REVENUE, $/TON 100% H2SO4	NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67200	193500	15500	22.50	20.70	41758300	4674700	37083600	37083600
2	7000	60900000	2900000	67200	193500	15500	22.50	20.70	41192300	4674700	36517600	73601200
3	7000	60900000	2900000	67200	193500	15500	22.50	20.70	40626400	4674700	35951700	109552900
4	7000	60900000	2900000	67200	193500	15500	22.50	20.70	40060400	4674700	35385700	144938600
5	7000	60900000	2900000	67200	193500	15500	22.50	20.70	39494400	4674700	34819700	179758300
6	7000	60900000	2900000	67200	193500	15500	22.50	20.70	38928500	4674700	34253800	214012100
7	7000	60900000	2900000	67200	193500	15500	22.50	20.70	38362500	4674700	33687800	247699900
8	7000	60900000	2900000	67200	193500	15500	22.50	20.70	37796500	4674700	33121800	280821700
9	7000	60900000	2900000	67200	193500	15500	22.50	20.70	37230600	4674700	32555900	313377600
10	7000	60900000	2900000	67200	193500	15500	22.50	20.70	36664600	4674700	31989900	345367500
11	5000	43500000	2071400	48000	138200	11100	22.50	20.70	31444100	3339300	28104800	373472300
12	5000	43500000	2071400	48000	138200	11100	22.50	20.70	30878200	3339300	27538900	401011200
13	5000	43500000	2071400	48000	138200	11100	22.50	20.70	30312200	3339300	26972900	427984100
14	5000	43500000	2071400	48000	138200	11100	22.50	20.70	29746200	3339300	26406900	454391000
15	5000	43500000	2071400	48000	138200	11100	22.50	20.70	29180300	3339300	25841000	480232000
16	3500	30450000	1450000	33600	96800	7700	22.50	20.70	25010200	2337400	22672800	502904800
17	3500	30450000	1450000	33600	96800	7700	22.50	20.70	24444200	2337400	22106800	525011600
18	3500	30450000	1450000	33600	96800	7700	22.50	20.70	23878300	2337400	21540900	546552500
19	3500	30450000	1450000	33600	96800	7700	22.50	20.70	23312300	2337400	20974900	567527400
20	3500	30450000	1450000	33600	96800	7700	22.50	20.70	22746300	2337400	20408900	587936300
21	1500	13050000	621400	14400	41500	3300	22.50	20.70	17075200	1002100	16073100	604009400
22	1500	13050000	621400	14400	41500	3300	22.50	20.70	16509200	1002100	15507100	619516500
23	1500	13050000	621400	14400	41500	3300	22.50	20.70	15943200	1002100	14941100	634457600
24	1500	13050000	621400	14400	41500	3300	22.50	20.70	15377300	1002100	14375200	648832800
25	1500	13050000	621400	14400	41500	3300	22.50	20.70	14811300	1002100	13809200	662642000
26	1500	13050000	621400	14400	41500	3300	22.50	20.70	14245300	1002100	13243200	675885200
27	1500	13050000	621400	14400	41500	3300	22.50	20.70	13679400	1002100	12677300	688562500
28	1500	13050000	621400	14400	41500	3300	22.50	20.70	13113400	1002100	12111300	700673800
29	1500	13050000	621400	14400	41500	3300	22.50	20.70	12547400	1002100	11545300	712219100
30	1500	13050000	621400	14400	41500	3300	22.50	20.70	11981500	1002100	10979400	723198500
TOT	127500	1109250000	52821000	1224000	3525000	282000			808350000	85151500	723198500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	15.30	1.61	13.69
MILLS PER KILOWATT-HOUR	6.34	0.67	5.67
CENTS PER MILLION BTU HEAT INPUT	72.87	7.67	65.20
DOLLARS PER TON OF SULFUR REMOVED	660.42	69.57	590.85
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	291550700	33189500	258361200

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	14.16	1.61	12.55
MILLS PER KILOWATT-HOUR	5.87	0.67	5.20
CENTS PER MILLION BTU HEAT INPUT	67.43	7.68	59.75
DOLLARS PER TON OF SULFUR REMOVED	611.09	69.57	541.52

TABLE A-55. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	487,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	12.0
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	12.0
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	13.5
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,868,000	7.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,944,000	24.6
Acid production (complete contact unit for sulfuric acid production)	6,138,000	16.9
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	972,000	2.7
Subtotal	34,167,000	94.0
Services, utilities, and miscellaneous	2,050,000	5.6
Total excluding pond	36,217,000	99.6
Pond	154,000	0.4
Total direct investment	36,371,000	100.0
Indirect Investment		
Engineering design and supervision	2,271,000	6.2
Architect and engineering contractor	564,000	1.6
Construction expense	4,946,000	13.6
Contractor fees	1,474,000	4.0
Total indirect investment	9,255,000	25.4
Contingency	9,125,000	25.1
Total fixed investment	54,751,000	150.5
Other Capital Charges		
Allowance for startup and modifications	5,460,000	15.0
Interest during construction	6,570,000	18.1
Total depreciable investment	66,781,000	183.6
Land	42,000	0.1
Working capital	1,652,000	4.5
Total capital investment	68,475,000	188.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-56. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	7,180 tons	103.00/ton	739,500	3.94
Catalyst	2,050 liters	2.50/liter	5,100	0.03
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.26
Filter aid	80 tons	189.00/ton	15,100	0.08
Total raw materials cost			808,300	4.31
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	3.16
Utilities				
Steam	1,714,900 MBtu	2.00/MBtu	3,429,800	18.28
Process water	5,774,800 kgal	0.12/kgal	693,000	3.69
Electricity	81,641,400 kWh	0.029/kWh	2,367,600	12.62
Heat credit	55,100 MBtu	2.00/MBtu	(110,200)	(0.59)
Maintenance				
Labor and material			2,177,600	11.61
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.77
Total conversion costs			9,296,100	49.54
Total direct costs			10,104,400	53.85
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,006,900	21.36
Average cost of capital and taxes at 8.6% of total capital investment			5,888,900	31.38
Overheads				
Plant, 50% of conversion costs less utilities			1,458,000	7.77
Administrative, 10% of operating labor			59,400	0.32
Marketing, 10% of byproduct sales revenue			306,000	1.63
Total indirect costs			11,719,200	62.46
Gross average annual revenue requirements			21,823,600	116.31
Byproduct Sales Revenue				
100% sulfuric acid	114,000 tons	25.00/ton 100% H_2SO_4	(2,850,000)	(15.19)
Sodium sulfate	9,110 tons	23.00/ton	(209,500)	(1.12)
Net average annual revenue requirements			18,764,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.36	12.51	0.60	474

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 39,620 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $36,371,000; total depreciable investment, $66,781,000; and total capital investment, $68,475,000.
- All tons shown are 2,000 lb.

TABLE A-57

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: 90% S REMOVAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 68475000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NA2SO4	NET REVENUE, $/TON 100% H2SO4	NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	39600	114000	9100	22.50	20.70	27406500	2753400	24653100	24653100
2	7000	31500000	1500000	39600	114000	9100	22.50	20.70	27023600	2753400	24270200	48923300
3	7000	31500000	1500000	39600	114000	9100	22.50	20.70	26640800	2753400	23887400	72810700
4	7000	31500000	1500000	39600	114000	9100	22.50	20.70	26257900	2753400	23504500	96315200
5	7000	31500000	1500000	39600	114000	9100	22.50	20.70	25875000	2753400	23121600	119436800
6	7000	31500000	1500000	39600	114000	9100	22.50	20.70	25492100	2753400	22738700	142175500
7	7000	31500000	1500000	39600	114000	9100	22.50	20.70	25109300	2753400	22355900	164531400
8	7000	31500000	1500000	39600	114000	9100	22.50	20.70	24726400	2753400	21973000	186504400
9	7000	31500000	1500000	39600	114000	9100	22.50	20.70	24343500	2753400	21590100	208094500
10	7000	31500000	1500000	39600	114000	9100	22.50	20.70	23960700	2753400	21207300	229301800
11	5000	22500000	1071400	28300	81400	6500	22.50	20.70	20717700	1966100	18751600	248053400
12	5000	22500000	1071400	28300	81400	6500	22.50	20.70	20334800	1966100	18368700	266422100
13	5000	22500000	1071400	28300	81400	6500	22.50	20.70	19951900	1966100	17985800	284407900
14	5000	22500000	1071400	28300	81400	6500	22.50	20.70	19569100	1966100	17603000	302010900
15	5000	22500000	1071400	28300	81400	6500	22.50	20.70	19186200	1966100	17220100	319231000
16	3500	15750000	750000	19800	57000	4600	22.50	20.70	16571200	1377700	15193500	334424500
17	3500	15750000	750000	19800	57000	4600	22.50	20.70	16188300	1377700	14810600	349235100
18	3500	15750000	750000	19800	57000	4600	22.50	20.70	15805500	1377700	14427800	363662900
19	3500	15750000	750000	19800	57000	4600	22.50	20.70	15422600	1377700	14044900	377707800
20	3500	15750000	750000	19800	57000	4600	22.50	20.70	15039700	1377700	13662000	391369800
21	1500	6750000	321400	8500	24400	2000	22.50	20.70	11450200	590400	10859800	402229600
22	1500	6750000	321400	8500	24400	2000	22.50	20.70	11067300	590400	10476900	412706500
23	1500	6750000	321400	8500	24400	2000	22.50	20.70	10684400	590400	10094000	422800500
24	1500	6750000	321400	8500	24400	2000	22.50	20.70	10301500	590400	9711100	432511600
25	1500	6750000	321400	8500	24400	2000	22.50	20.70	9918700	590400	9328300	441839900
26	1500	6750000	321400	8500	24400	2000	22.50	20.70	9535800	590400	8945400	450785300
27	1500	6750000	321400	8500	24400	2000	22.50	20.70	9152900	590400	8562500	459347800
28	1500	6750000	321400	8500	24400	2000	22.50	20.70	8770100	590400	8179700	467527500
29	1500	6750000	321400	8500	24400	2000	22.50	20.70	8387200	590400	7796800	475324300
30	1500	6750000	321400	8500	24400	2000	22.50	20.70	8004300	590400	7413900	482738200
TOT	127500	573750000	27321000	721500	2076000	166500			532895200	50157000	482738200	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	19.50	1.83	17.67
MILLS PER KILOWATT-HOUR	8.36	0.79	7.57
CENTS PER MILLION BTU HEAT INPUT	92.88	8.74	84.14
DOLLARS PER TON OF SULFUR REMOVED	738.59	69.51	669.08

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 191409700 19548600 171861100

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	17.97	1.83	16.14
MILLS PER KILOWATT-HOUR	7.70	0.78	6.92
CENTS PER MILLION BTU HEAT INPUT	85.59	8.74	76.85
DOLLARS PER TON OF SULFUR REMOVED	680.69	69.52	611.17

TABLE A-58. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: oil-fired, existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	311,000	1.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	3,908,000	19.0
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,213,000	20.5
Stack gas reheat (four direct oil-fired reheaters)	1,063,000	5.2
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,577,000	7.7
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,603,000	22.4
Acid production (complete contact unit for sulfuric acid production)	3,158,000	15.4
Acid storage (storage and shipping facilities for 30-day production of sulfuric acid)	534,000	2.6
Subtotal	19,367,000	94.3
Services, utilities, and miscellaneous	1,162,000	5.7
Total direct investment	20,529,000	100.0
Indirect Investment		
Engineering design and supervision	1,868,000	9.1
Architect and engineering contractor	467,000	2.3
Construction expense	3,070,000	15.0
Contractor fees	954,000	4.6
Total indirect investment	6,359,000	31.0
Contingency	5,378,000	26.2
Total fixed investment	32,266,000	157.2
Other Capital Charges		
Allowance for startup and modifications	3,227,000	15.7
Interest during construction	3,872,000	18.9
Total depreciable investment	39,365,000	191.8
Land	27,000	0.1
Working capital	987,000	4.8
Total capital investment	40,379,000	196.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-59. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: oil-fired, existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,780 tons	103.00/ton	286,300	2.39
Catalyst	790 liters	2.50/liter	2,000	0.02
Agricultural limestone	2,740 tons	15.00/ton	41,100	0.34
Filter aid	31 tons	189.00/ton	5,900	0.05
Total raw materials cost			335,300	2.80
Conversion costs				
Operating labor and supervision	45,440 man-hr	12.50/man-hr	568,000	4.74
Utilities				
Fuel oil	2,467,400 gal	0.40/gal	987,000	8.23
Steam	501,300 MBtu	2.00/MBtu	1,002,600	8.36
Process water	2,322,000 kgal	0.12/kgal	278,700	2.32
Electricity	53,159,700 kWh	0.029/kWh	1,541,600	12.85
Heat credit	21,300 MBtu	2.00/MBtu	(42,600)	(0.35)
Maintenance				
Labor and material			1,231,700	10.27
Analyses	8,130 man-hr	17.00/man-hr	138,200	1.15
Total conversion costs			5,705,200	47.57
Total direct costs			6,040,500	50.37
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			2,519,400	21.01
Average cost of capital and taxes at 8.6% of total capital investment			3,472,600	28.95
Overheads				
Plant, 50% of conversion costs less utilities			969,000	8.08
Administrative, 10% of operating labor			56,800	0.47
Marketing, 10% of byproduct sales revenue			118,400	0.99
Total indirect costs			7,136,200	59.50
Gross average annual revenue requirements			13,176,700	109.87
Byproduct Sales Revenue				
100% sulfuric acid	44,100 tons	25.00/ton 100% H_2SO_4	(1,102,500)	(9.19)
Sodium sulfate	3,530 tons	23.00/ton	(81,200)	(0.68)
Net average annual revenue requirements			11,993,000	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.43	2.24	0.37	782

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Oil burned, 5,350,000 bbl/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 15,330 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $20,529,000; total depreciable investment, $39,365,000; and total capital investment, $40,379,000.
- All tons shown are 2,000 lb.

TABLE A-60

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: OIL FIRED EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 40379000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NA2SO4	NET REVENUE, $/TON 100% H2SO4	NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	32200000	5324100	15300	44100	3500	22.50	20.70	16764000	1064800	15699200	15699200
7	7000	32200000	5324100	15300	44100	3500	22.50	20.70	16493200	1064800	15428400	31127600
8	7000	32200000	5324100	15300	44100	3500	22.50	20.70	16222300	1064800	15157500	46285100
9	7000	32200000	5324100	15300	44100	3500	22.50	20.70	15951500	1064800	14886700	61171800
10	7000	32200000	5324100	15300	44100	3500	22.50	20.70	15680700	1064800	14615900	75787700
11	5000	23000000	3802900	11000	31500	2500	22.50	20.70	13708800	760600	12948200	88735900
12	5000	23000000	3802900	11000	31500	2500	22.50	20.70	13438000	760600	12677400	101413300
13	5000	23000000	3802900	11000	31500	2500	22.50	20.70	13167200	760600	12406600	113819900
14	5000	23000000	3802900	11000	31500	2500	22.50	20.70	12896300	760600	12135700	125955600
15	5000	23000000	3802900	11000	31500	2500	22.50	20.70	12625500	760600	11864900	137820500
16	3500	16100000	2662000	7700	22100	1800	22.50	20.70	11022600	534600	10488000	148308500
17	3500	16100000	2662000	7700	22100	1800	22.50	20.70	10751700	534600	10217100	158525600
18	3500	16100000	2662000	7700	22100	1800	22.50	20.70	10480900	534600	9946300	168471900
19	3500	16100000	2662000	7700	22100	1800	22.50	20.70	10210100	534600	9675500	178147400
20	3500	16100000	2662000	7700	22100	1800	22.50	20.70	9939300	534600	9404700	187552100
21	1500	6900000	1140900	3300	9500	800	22.50	20.70	7743200	230400	7512800	195064900
22	1500	6900000	1140900	3300	9500	800	22.50	20.70	7472400	230400	7242000	202306900
23	1500	6900000	1140900	3300	9500	800	22.50	20.70	7201600	230400	6971200	209278100
24	1500	6900000	1140900	3300	9500	800	22.50	20.70	6930700	230400	6700300	215978400
25	1500	6900000	1140900	3300	9500	800	22.50	20.70	6659900	230400	6429500	222407900
26	1500	6900000	1140900	3300	9500	800	22.50	20.70	6389100	230400	6158700	228566600
27	1500	6900000	1140900	3300	9500	800	22.50	20.70	6118200	230400	5887800	234454400
28	1500	6900000	1140900	3300	9500	800	22.50	20.70	5847400	230400	5617000	240071400
29	1500	6900000	1140900	3300	9500	800	22.50	20.70	5576600	230400	5346200	245417600
30	1500	6900000	1140900	3300	9500	800	22.50	20.70	5305700	230400	5075300	250492900
TOT	92500	425500000	70354000	203000	583500	47000			264596900	14104000	250492900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER BARREL OF OIL BURNED	3.76	0.20	3.56
MILLS PER KILOWATT-HOUR	5.72	0.30	5.42
CENTS PER MILLION BTU HEAT INPUT	62.18	3.31	58.87
DOLLARS PER TON OF SULFUR REMOVED	1303.43	69.47	1233.96
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	107390400	6381000	101009400

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER BARREL OF OIL BURNED	3.37	0.20	3.17
MILLS PER KILOWATT-HOUR	5.12	0.30	4.82
CENTS PER MILLION BTU HEAT INPUT	55.70	3.31	52.39
DOLLARS PER TON OF SULFUR REMOVED	1169.83	69.51	1100.32

TABLE A-61. WELLMAN-LORD/SULFURIC ACID PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: wet-scrubbing fly ash removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,642,000	15.3
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	14.3
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.7
Fly ash removal (four scrubbers and entrainment separators, tanks, agitators, and pumps)	5,296,000	17.5
ESP credit	(4,713,000)	(15.5)
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	8.7
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,161,000	26.9
Acid production (complete contact unit for sulfuric acid production)	5,600,000	18.5
Acid storage (storage and shipping facilities for 30-day production) of sulfuric acid)	895,000	3.0
Subtotal	28,468,000	93.9
Services, utilities, and miscellaneous	1,708,000	5.6
Total excluding pond	30,176,000	99.5
Pond	154,000	0.5
Total direct investment	30,330,000	100.0
Indirect Investment		
Engineering design and supervision	2,233,000	7.4
Architect and engineering contractor	555,000	1.8
Construction expense	4,255,000	14.0
Contractor fees	1,284,000	4.2
Total indirect investment	8,327,000	27.4
Contingency	7,731,000	25.5
Total fixed investment	46,388,000	152.9
Other Capital Charges		
Allowance for startup and modifications	4,623,000	15.2
Interest during construction	5,567,000	18.4
Total depreciable investment	56,578,000	186.5
Land	42,000	0.1
Working capital	1,558,000	5.2
Total capital investment	58,178,000	191.8

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-62. WELLMAN-LORD/SULFURIC ACID PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: wet-scrubbing fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	3.75
Catalyst	1,800 liters	2.50/liter	4,500	0.02
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.28
Filter aid	70 tons	189.00/ton	13,200	0.08
Total raw materials cost			715,200	4.13
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	3.43
Utilities				
Steam	1,556,600 MBtu	2.00/MBtu	3,113,200	17.98
Process water	5,092,500 kgal	0.12/kgal	611,100	3.53
Electricity	113,923,900 kWh	0.029/kWh	3,303,800	19.09
Heat credit	48,400 MBtu	2.00/MBtu	(96,800)	(0.56)
ESP electricity credit	7,114,900 kWh	0.029/kWh	(206,300)	(1.19)
Maintenance				
Labor and material			1,815,200	10.49
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.83
Total conversion costs			9,278,500	53.60
Total direct costs			9,993,700	57.73
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,394,700	19.61
Average cost of capital and taxes at 8.6% of total capital investment			5,003,300	28.91
Overheads				
Plant, 50% of conversion costs less utilities			1,276,800	7.38
Administrative, 10% of operating labor			59,400	0.34
Marketing, 10% of byproduct sales revenue			268,700	1.55
Total indirect costs			10,002,900	57.79
Gross average annual revenue requirements			19,996,600	115.52
Byproduct Sales Revenue				
100% sulfuric acid	100,100 tons	25.00/ton 100% H_2SO_4	(2,502,500)	(14.46)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(1.06)
Net average annual revenue requirements			17,310,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.95	11.54	0.55	498

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $30,330,000; total depreciable investment, $56,578,000; and total capital investment, $58,178,000.
- All tons shown are 2,000 lb.

TABLE A-63

WELLMAN-LORD/ SULFURIC ACID PROCESS VARIATION FROM BASE CASE: WET SCRUBBING FLY ASH REMOVAL, REGULATED CO, ECONOMICS

TOTAL CAPITAL INVESTMENT 58175000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR 100% H2SO4	NA2SO4	NET REVENUE, $/TON 100% H2SO4	NA2SO4	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	100100	8000	22.50	20.70	24731300	2417900	22313400	22313400
2	7000	31500000	1500000	34800	100100	8000	22.50	20.70	24406900	2417900	21989000	44302400
3	7000	31500000	1500000	34800	100100	8000	22.50	20.70	24082600	2417900	21664700	65967100
4	7000	31500000	1500000	34800	100100	8000	22.50	20.70	23758200	2417900	21340300	87307400
5	7000	31500000	1500000	34800	100100	8000	22.50	20.70	23433800	2417900	21015900	108323300
6	7000	31500000	1500000	34800	100100	8000	22.50	20.70	23109400	2417900	20691500	129014800
7	7000	31500000	1500000	34800	100100	8000	22.50	20.70	22785100	2417900	20367200	149382000
8	7000	31500000	1500000	34800	100100	8000	22.50	20.70	22460700	2417900	20042800	169424800
9	7000	31500000	1500000	34800	100100	8000	22.50	20.70	22136300	2417900	19718400	189143200
10	7000	31500000	1500000	34800	100100	8000	22.50	20.70	21811900	2417900	19394000	208537200
11	5000	22500000	1071400	24800	71500	5700	22.50	20.70	18654900	1726800	16928100	225465300
12	5000	22500000	1071400	24800	71500	5700	22.50	20.70	18330500	1726800	16603700	242069000
13	5000	22500000	1071400	24800	71500	5700	22.50	20.70	18006100	1726800	16279300	258348300
14	5000	22500000	1071400	24800	71500	5700	22.50	20.70	17681700	1726800	15954900	274303200
15	5000	22500000	1071400	24800	71500	5700	22.50	20.70	17357400	1726800	15630600	289933800
16	3500	15750000	750000	17400	50100	4000	22.50	20.70	14832600	1210100	13622500	303556300
17	3500	15750000	750000	17400	50100	4000	22.50	20.70	14508200	1210100	13298100	316854400
18	3500	15750000	750000	17400	50100	4000	22.50	20.70	14183800	1210100	12973700	329828100
19	3500	15750000	750000	17400	50100	4000	22.50	20.70	13859500	1210100	12649400	342477500
20	3500	15750000	750000	17400	50100	4000	22.50	20.70	13535100	1210100	12325000	354802500
21	1500	6750000	321400	7500	21500	1700	22.50	20.70	10075200	519000	9556200	364358700
22	1500	6750000	321400	7500	21500	1700	22.50	20.70	9750800	519000	9231800	373590500
23	1500	6750000	321400	7500	21500	1700	22.50	20.70	9426500	519000	8907500	382498000
24	1500	6750000	321400	7500	21500	1700	22.50	20.70	9102100	519000	8583100	391081100
25	1500	6750000	321400	7500	21500	1700	22.50	20.70	8777700	519000	8258700	399339800
26	1500	6750000	321400	7500	21500	1700	22.50	20.70	8453300	519000	7934300	407274100
27	1500	6750000	321400	7500	21500	1700	22.50	20.70	8129000	519000	7610000	414884100
28	1500	6750000	321400	7500	21500	1700	22.50	20.70	7804600	519000	7285600	422169700
29	1500	6750000	321400	7500	21500	1700	22.50	20.70	7480200	519000	6961200	429130900
30	1500	6750000	321400	7500	21500	1700	22.50	20.70	7155800	519000	6636800	435767700
TOT 127500		573750000	27321000	634000	1824000	145500			479821200	44053500	435767700	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

MILLS PER KILOWATT-HOUR	7.53	0.69	6.84
CENTS PER MILLION BTU HEAT INPUT	83.63	7.68	75.95
DOLLARS PER TON OF SULFUR REMOVED	756.82	69.49	687.33

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 172986400 17167600 155818800

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

MILLS PER KILOWATT-HOUR	6.96	0.69	6.27
CENTS PER MILLION BTU HEAT INPUT	77.35	7.68	69.67
DOLLARS PER TON OF SULFUR REMOVED	700.35	69.50	630.85

IHN215I CONVERT - ILLEGAL DECIMAL CHARACTER S

SODIUM CARBONATE 6300TONS 103.00/TON 1.0

TRACEBACK ROUTINE CALLED FROM ISN REG. 14 REC. 15 REG. 0 REG. 1

IBCOM 000BF910 000CB1EC 0000000F 000BFBF4

TABLE A-64. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	305,000	1.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	1,952,000	10.6
SO_2 absorption (two absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	1,902,000	10.4
Stack gas reheat (two indirect steam reheaters)	504,000	2.7
Chloride purge (two chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	2,153,000	11.7
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,534,000	8.4
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,544,000	24.7
Sulfur production (complete unit for sulfur production)	4,024,000	21.9
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	377,000	2.1
Subtotal	17,295,000	94.2
Services, utilities, and miscellaneous	1,038,000	5.6
Total excluding pond	18,333,000	99.8
Pond	31,000	0.2
Total direct investment	18,364,000	100.0
Indirect Investment		
Engineering design and supervision	1,590,000	8.6
Architect and engineering contractor	397,000	2.2
Construction expense	2,803,000	15.2
Contractor fees	877,000	4.8
Total indirect investment	5,667,000	30.8
Contingency	4,806,000	26.2
Total fixed investment	28,837,000	157.0
Other Capital Charges		
Allowance for startup and modifications	2,881,000	15.7
Interest during construction	3,460,000	18.9
Total depreciable investment	35,178,000	191.6
Land	16,000	0.1
Working capital	925,000	5.0
Total capital investment	36,119,000	196.7

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-65. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,660 tons	103.00/ton	274,000	2.46
Agricultural limestone	1,370 tons	15.00/ton	20,600	0.18
Filter aid	30 tons	189.00/ton	5,700	0.05
Anthracite coal	14,010 tons	60.00/ton	840,600	7.55
Total raw materials cost			1,140,900	10.24
Conversion costs				
Operating labor and supervision	30,040 man-hr	12.50/man-hr	375,500	3.37
Utilities				
Fuel oil	335,100 gal	0.40/gal	134,000	1.20
Steam	662,600 MBtu	2.00/MBtu	1,325,200	11.90
Process water	1,699,100 kgal	0.12/kgal	203,900	1.83
Electricity	32,658,000 kWh	0.031/kWh	1,012,400	9.09
Heat credit	78,400 MBtu	2.00/MBtu	(156,800)	(1.41)
Maintenance				
Labor and material			1,284,200	11.53
Analyses	4,480 man-hr	17.00/man-hr	76,200	0.68
Total conversion costs			4,254,600	38.19
Total direct costs			5,395,500	48.43
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			2,462,500	22.10
Average cost of capital and taxes at 8.6% of total capital investment			3,106,200	27.88
Overheads				
Plant, 50% of conversion costs less utilities			868,000	7.79
Administrative, 10% of operating labor			37,600	0.34
Marketing, 10% of byproduct sales revenue			81,000	0.73
Total indirect costs			6,555,300	58.84
Gross average annual revenue requirements			11,950,800	107.27
Byproduct Sales Revenue				
Sulfur	13,800 tons	40.00/ton	(552,000)	(4.95)
Sodium sulfate	3,380 tons	23.00/ton	(77,700)	(0.70)
Spent anthracite	7,200 tons	25.00/ton	(180,000)	(1.62)
Net average annual revenue requirements			11,141,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	7.96	17.59	0.84	759

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 20 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 14,680 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $18,364,000; total depreciable investment, $35,178,000; and total capital investment, $36,119,000.
- All tons shown are 2,000 lb.

TABLE A-66

WELL MAN-LORD/RESOX PROCESS VARIATION FROM BASE CASE: 200 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 36119000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU/YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL/YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11	5000	9500000	452400	10500	9900	7600	36.00	21.93	14039000	523100	13515900	13515900
12	5000	9500000	452400	10500	9900	7600	36.00	21.93	13736400	523100	13213300	26729200
13	5000	9500000	452400	10500	9900	7600	36.00	21.93	13433900	523100	12910800	39640000
14	5000	9500000	452400	10500	9900	7600	36.00	21.93	13131400	523100	12608300	52248300
15	5000	9500000	452400	10500	9900	7600	36.00	21.93	12828800	523100	12305700	64554000
16	3500	6650000	316700	7300	6900	5300	36.00	21.93	11331400	364600	10966800	75520800
17	3500	6650000	316700	7300	6900	5300	36.00	21.93	11028900	364600	10664300	86185100
18	3500	6650000	316700	7300	6900	5300	36.00	21.93	10726400	364600	10361800	96546900
19	3500	6650000	316700	7300	6900	5300	36.00	21.93	10423800	364600	10059200	106606100
20	3500	6650000	316700	7300	6900	5300	36.00	21.93	10121300	364600	9756700	116362800
21	1500	2850000	135700	3100	3000	2300	36.00	21.93	8087200	158400	7928800	124291600
22	1500	2850000	135700	3100	3000	2300	36.00	21.93	7784600	158400	7626200	131917800
23	1500	2850000	135700	3100	3000	2300	36.00	21.93	7482100	158400	7323700	139241500
24	1500	2850000	135700	3100	3000	2300	36.00	21.93	7179600	158400	7021200	146262700
25	1500	2850000	135700	3100	3000	2300	36.00	21.93	6877000	158400	6718600	152981300
26	1500	2850000	135700	3100	3000	2300	36.00	21.93	6574500	158400	6416100	159397400
27	1500	2850000	135700	3100	3000	2300	36.00	21.93	6272000	158400	6113600	165511000
28	1500	2850000	135700	3100	3000	2300	36.00	21.93	5969400	158400	5811000	171322000
29	1500	2850000	135700	3100	3000	2300	36.00	21.93	5666900	158400	5508500	176830500
30	1500	2850000	135700	3100	3000	2300	36.00	21.93	5366400	158400	5206000	182036500
TOT	57500	109250000	5202500	120000	114000	87500			188059000	6022500	182036500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	36.15	1.16	34.99
MILLS PER KILOWATT-HOUR	16.35	0.52	15.83
CENTS PER MILLION BTU HEAT INPUT	172.14	5.52	166.62
DOLLARS PER TON OF SULFUR REMOVED	1567.16	50.19	1516.97
PROCESS COST (DISCOUNTED) AT 11.6% TO INITIAL YEAR, DOLLARS	85255200	2975000	82280200

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	33.13	1.16	31.97
MILLS PER KILOWATT-HOUR	14.99	0.52	14.47
CENTS PER MILLION BTU HEAT INPUT	157.77	5.50	152.27
DOLLARS PER TON OF SULFUR REMOVED	1432.86	50.00	1382.86

TABLE A-67. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	301,000	1.7
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	1,908,000	10.6
SO_2 absorption (two absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	1,858,000	10.3
Stack gas reheat (two indirect steam reheaters)	493,000	2.7
Chloride purge (two chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	2,104,000	11.7
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,503,000	8.4
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,444,000	24.7
Sulfur production (complete unit for sulfur production)	3,936,000	21.9
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	369,000	2.1
Subtotal	16,916,000	94.1
Services, utilities, and miscellaneous	1,015,000	5.6
Total excluding pond	17,931,000	99.7
Pond	56,000	0.3
Total direct investment	17,987,000	100.0
Indirect Investment		
Engineering design and supervision	1,588,000	8.8
Architect and engineering contractor	395,000	2.2
Construction expense	2,756,000	15.4
Contractor fees	863,000	4.8
Total indirect investment	5,602,000	31.2
Contingency	4,718,000	26.2
Total fixed investment	28,307,000	157.4
Other Capital Charges		
Allowance for startup and modifications	2,825,000	15.7
Interest during construction	3,397,000	18.9
Total depreciable investment	34,529,000	192.0
Land	16,000	0.1
Working capital	902,000	5.0
Total capital investment	35,447,000	197.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-68. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW new)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,580 tons	103.00/ton	265,700	2.52
Agricultural limestone	1,320 tons	15.00/ton	19,800	0.19
Filter aid	29 tons	189.00/ton	5,500	0.05
Anthracite coal	13,570 tons	60.00/ton	814,200	7.71
Total raw materials cost			1,105,200	10.47
Conversion costs				
Operating labor and supervision	30,040 man-hr	12.50/man-hr	375,500	3.56
Utilities				
Fuel oil	324,600 gal	0.40/gal	129,800	1.23
Steam	641,700 MBtu	2.00/MBtu	1,283,400	12.16
Process water	1,645,500 kgal	0.12/kgal	197,500	1.87
Electricity	31,649,000 kWh	0.031/kWh	981,100	9.29
Heat credit	76,000 MBtu	2.00/MBtu	(152,000)	(1.44)
Maintenance				
Labor and material			1,256,800	11.90
Analyses	4,480 man-hr	17.00/man-hr	76,200	0.72
Total conversion costs			4,148,300	39.29
Total direct costs			5,253,500	49.76
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,071,700	19.62
Average cost of capital and taxes at 8.6% of total capital investment			3,048,400	28.88
Overheads				
Plant, 50% of conversion costs less utilities			854,200	8.09
Administrative, 10% of operating labor			37,600	0.36
Marketing, 10% of byproduct sales revenue			78,600	0.74
Total indirect costs			6,090,500	57.69
Gross average annual revenue requirements			11,344,000	107.45
Byproduct Sales Revenue				
Sulfur	13,400 tons	40.00/ton	(536,000)	(5.08)
Sodium sulfate	3,270 tons	23.00/ton	(75,200)	(0.71)
Spent anthracite	7,000 tons	25.00/ton	(175,000)	(1.66)
Net average annual revenue requirements			10,557,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	7.54	17.22	0.82	742

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 613,200 tons/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 14,220 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $17,987,000; total depreciable investment, $34,529,000; and total capital investment, $35,447,000.
- All tons shown are 2,000 lb.

TABLE A-69

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: 200 MW, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 35447000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14200	13400	10300	36.00	21.93	14314300	708300	13606000	13606000
2	7000	12880000	613300	14200	13400	10300	36.00	21.93	14116300	708300	13408000	27014000
3	7000	12880000	613300	14200	13400	10300	36.00	21.93	13918300	708300	13210000	40224000
4	7000	12880000	613300	14200	13400	10300	36.00	21.93	13720400	708300	13012100	53236100
5	7000	12880000	613300	14200	13400	10300	36.00	21.93	13522500	708300	12814100	66050200
6	7000	12880000	613300	14200	13400	10300	36.00	21.93	13324400	708300	12616100	78666300
7	7000	12880000	613300	14200	13400	10300	36.00	21.93	13126500	708300	12418200	91084500
8	7000	12880000	613300	14200	13400	10300	36.00	21.93	12928500	708300	12220200	103304700
9	7000	12880000	613300	14200	13400	10300	36.00	21.93	12730500	708300	12022200	115326900
10	7000	12880000	613300	14200	13400	10300	36.00	21.93	12532500	708300	11824200	127151100
11	5000	9200000	438100	10200	9600	7300	36.00	21.93	10851200	505700	10345500	137496600
12	5000	9200000	438100	10200	9600	7300	36.00	21.93	10653200	505700	10147500	147644100
13	5000	9200000	438100	10200	9600	7300	36.00	21.93	10455200	505700	9949500	157593600
14	5000	9200000	438100	10200	9600	7300	36.00	21.93	10257200	505700	9751500	167345100
15	5000	9200000	438100	10200	9600	7300	36.00	21.93	10059300	505700	9553600	176898700
16	3500	6440000	306700	7100	6700	5100	36.00	21.93	8697500	353000	8344500	185243200
17	3500	6440000	306700	7100	6700	5100	36.00	21.93	8499500	353000	8146500	193389700
18	3500	6440000	306700	7100	6700	5100	36.00	21.93	8301600	353000	7948600	201338300
19	3500	6440000	306700	7100	6700	5100	36.00	21.93	8103600	353000	7750600	209088900
20	3500	6440000	306700	7100	6700	5100	36.00	21.93	7905600	353000	7552600	216641500
21	1500	2760000	131400	3000	2900	2200	36.00	21.93	6019400	152600	5866800	222508300
22	1500	2760000	131400	3000	2900	2200	36.00	21.93	5821500	152600	5668900	228177200
23	1500	2760000	131400	3000	2900	2200	36.00	21.93	5623500	152600	5470900	233648100
24	1500	2760000	131400	3000	2900	2200	36.00	21.93	5425500	152600	5272900	238921000
25	1500	2760000	131400	3000	2900	2200	36.00	21.93	5227600	152600	5075000	243996000
26	1500	2760000	131400	3000	2900	2200	36.00	21.93	5029600	152600	4877000	248873000
27	1500	2760000	131400	3000	2900	2200	36.00	21.93	4831600	152600	4679000	253552000
28	1500	2760000	131400	3000	2900	2200	36.00	21.93	4633600	152600	4481000	258033000
29	1500	2760000	131400	3000	2900	2200	36.00	21.93	4435700	152600	4283100	262316100
30	1500	2760000	131400	3000	2900	2200	36.00	21.93	4237700	152600	4085100	266401200
TOT	127500	234600000	11171000	258500	244500	187000			279303700	12902500	266401200	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	25.00	1.15	23.85
MILLS PER KILOWATT-HOUR	10.95	0.50	10.45
CENTS PER MILLION BTU HEAT INPUT	119.06	5.50	113.56
DOLLARS PER TON OF SULFUR REMOVED	1080.48	49.91	1030.57

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 100117100 5028200 95088900

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	22.99	1.15	21.84
MILLS PER KILOWATT-HOUR	10.07	0.50	9.57
CENTS PER MILLION BTU HEAT INPUT	109.48	5.49	103.99
DOLLARS PER TON OF SULFUR REMOVED	993.23	49.89	943.34

TABLE A-70. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 500 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	463,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,442,000	12.1
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,426,000	12.0
Stack gas reheat (four indirect steam reheaters)	1,153,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,977,000	13.5
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,678,000	7.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,432,000	22.9
Sulfur production (complete unit for sulfur production)	7,398,000	20.1
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	652,000	1.8
Subtotal	34,621,000	94.1
Services, utilities, and miscellaneous	2,077,000	5.6
Total excluding pond	36,698,000	99.7
Pond	123,000	0.3
Total direct investment	36,821,000	100.0
Indirect Investment		
Engineering design and supervision	2,356,000	6.4
Architect and engineering contractor	586,000	1.6
Construction expense	4,996,000	13.6
Contractor fees	1,488,000	4.0
Total indirect investment	9,426,000	25.6
Contingency	9,249,000	25.1
Total fixed investment	55,496,000	150.7
Other Capital Charges		
Allowance for startup and modifications	5,537,000	15.0
Interest during construction	6,660,000	18.1
Total depreciable investment	67,693,000	183.8
Land	41,000	0.1
Working capital	1,956,000	5.4
Total capital investment	69,690,000	189.3

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-71. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 500 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,440 tons	103.00/ton	663,300	3.06
Agricultural limestone	3,310 tons	15.00/ton	49,700	0.23
Filter aid	72 tons	189.00/ton	13,600	0.06
Anthracite coal	33,920 tons	60.00/ton	2,035,200	9.37
Total raw materials cost			2,761,800	12.72
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.74
Utilities				
Fuel oil	8[illegible],400 gal	0.40/gal	324,600	1.50
Steam	1,604,200 MBtu	2.00/MBtu	3,208,400	14.78
Process water	4,113,600 kgal	0.12/kgal	493,600	2.27
Electricity	78,217,000 kWh	0.029/kWh	2,268,300	10.45
Heat credit	189,900 MBtu	2.00/MBtu	(379,800)	(1.75)
Maintenance				
Labor and material			2,205,600	10.16
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.66
Total conversion costs			8,859,000	40.81
Total direct costs			11,620,800	53.53
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			4,332,400	19.96
Average cost of capital and taxes at 8.6% of total capital investment			5,993,300	27.61
Overheads				
Plant, 50% of conversion costs less utilities			1,472,000	6.78
Administrative, 10% of operating labor			59,400	0.27
Marketing, 10% of byproduct sales revenue			196,600	0.90
Total indirect costs			12,053,700	55.52
Gross average annual revenue requirements			23,674,500	109.05
Byproduct Sales Revenue				
Sulfur	33,500 tons	40.00/ton	(1,340,000)	(6.17)
Sodium sulfate	8,180 tons	23.00/ton	(188,100)	(0.87)
Spent anthracite	17,500 tons	25.00/ton	(437,500)	(2.01)
Net average annual revenue requirements			21,708,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.20	14.16	0.67	611

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 35,550 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $36,821,000; total depreciable investment, $67,693,000; and total capital investment, $69,690,000.
- All tons shown are 2,000 lb.

TABLE A-72

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: 500 MW EXISTING, REGULATED CO, ECONOMICS

TOTAL CAPITAL INVESTMENT 69690000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/ Kw	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	32200000	1533300	35600	33500	25700	36.00	21.93	29922700	1769600	28153100	28153100
7	7000	32200000	1533300	35600	33500	25700	36.00	21.93	29457000	1769600	27687400	55840500
8	7000	32200000	1533300	35600	33500	25700	36.00	21.93	28991200	1769600	27221600	83062100
9	7000	32200000	1533300	35600	33500	25700	36.00	21.93	28525500	1769600	26755900	109818000
10	7000	32200000	1533300	35600	33500	25700	36.00	21.93	28059800	1769600	26290200	136108200
11	5000	23000000	1095200	25400	23900	18300	36.00	21.93	24300900	1261700	23039200	159147400
12	5000	23000000	1095200	25400	23900	18300	36.00	21.93	23835100	1261700	22573400	181720800
13	5000	23000000	1095200	25400	23900	18300	36.00	21.93	23369400	1261700	22107700	203828500
14	5000	23000000	1095200	25400	23900	18300	36.00	21.93	22903700	1261700	21642000	225470500
15	5000	23000000	1095200	25400	23900	18300	36.00	21.93	22438000	1261700	21176300	246646800
16	3500	16100000	766700	17800	16800	12800	36.00	21.93	19414400	885500	18528900	265175700
17	3500	16100000	766700	17800	16800	12800	36.00	21.93	18948700	885500	18063200	283238900
18	3500	16100000	766700	17800	16800	12800	36.00	21.93	18483000	885500	17597500	300836400
19	3500	16100000	766700	17800	16800	12800	36.00	21.93	18017300	885500	17131800	317968200
20	3500	16100000	766700	17800	16800	12800	36.00	21.93	17551500	885500	16666000	334634200
21	1500	6900000	328600	7600	7200	5500	36.00	21.93	13443000	379800	13063200	347697400
22	1500	6900000	328600	7600	7200	5500	36.00	21.93	12977300	379800	12597500	360294900
23	1500	6900000	328600	7600	7200	5500	36.00	21.93	12511600	379800	12131800	372426700
24	1500	6900000	328600	7600	7200	5500	36.00	21.93	12045800	379800	11666000	384092700
25	1500	6900000	328600	7600	7200	5500	36.00	21.93	11580100	379800	11200300	395293000
26	1500	6900000	328600	7600	7200	5500	36.00	21.93	11114400	379800	10734600	406027600
27	1500	6900000	328600	7600	7200	5500	36.00	21.93	10648700	379800	10268900	416296500
28	1500	6900000	328600	7600	7200	5500	36.00	21.93	10182900	379800	9803100	426099600
29	1500	6900000	328600	7600	7200	5500	36.00	21.93	9717200	379800	9337400	435437000
30	1500	6900000	328600	7600	7200	5500	36.00	21.93	9251500	379800	8871700	444308700
TOT	92500	425500000	20262000	470000	443000	339000			467690700	23382000	444308700	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	23.08	1.15	21.93
MILLS PER KILOWATT-HOUR	10.11	0.50	9.61
CENTS PER MILLION BTU HEAT INPUT	109.92	5.50	104.42
DOLLARS PER TON OF SULFUR REMOVED	995.09	49.75	945.34
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	190886000	10592700	180293300

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	20.79	1.15	19.64
MILLS PER KILOWATT-HOUR	9.11	0.51	8.60
CENTS PER MILLION BTU HEAT INPUT	99.00	5.49	93.51
DOLLARS PER TON OF SULFUR REMOVED	895.76	49.71	846.05

TABLE A-73. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 2.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	318,000	1.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	15.7
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	15.6
Stack gas reheat (four indirect steam reheaters)	1,136,000	4.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	17.5
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,619,000	5.8
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,826,000	17.2
Sulfur production (complete unit for sulfur production)	4,264,000	15.3
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	397,000	1.4
Subtotal	26,182,000	93.8
Services, utilities, and miscellaneous	1,571,000	5.6
Total excluding pond	27,753,000	99.4
Pond	154,000	0.6
Total direct investment	27,907,000	100.0
Indirect Investment		
Engineering design and supervision	2,140,000	7.7
Architect and engineering contractor	532,000	1.9
Construction expense	3,971,000	14.2
Contractor fees	1,205,000	4.3
Total indirect investment	7,848,000	28.1
Contingency	7,151,000	25.6
Total fixed investment	42,906,000	153.7
Other Capital Charges		
Allowance for startup and modifications	4,275,000	15.4
Interest during construction	5,149,000	18.4
Total depreciable investment	52,330,000	187.5
Land	44,000	0.2
Working capital	1,253,000	4.5
Total capital investment	53,627,000	192.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-74. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 2.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,900 tons	103.00/ton	298,700	1.91
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.31
Filter aid	32 tons	189.00/ton	6,000	0.04
Anthracite coal	15,270 tons	60.00/ton	916,200	5.86
Total raw materials cost			1,269,500	8.12
Conversion costs				
Operating labor and supervision	42,550 man-hr	12.50/man-hr	531,900	3.40
Utilities				
Fuel oil	365,200 gal	0.40/gal	146,100	0.94
Steam	946,900 MBtu	2.00/MBtu	1,893,800	12.12
Process water	1,954,300 kgal	0.12/kgal	234,500	1.50
Electricity	60,417,000 kWh	0.029/kWh	1,752,100	11.21
Heat credit	85,500 MBtu	2.00/MBtu	(171,000)	(1.09)
Maintenance				
Labor and material			1,669,800	10.68
Analyses	7,610 man-hr	17.00/man-hr	129,400	0.83
Total conversion costs			6,186,600	39.59
Total direct costs			7,456,100	47.71
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,139,800	20.09
Average cost of capital and taxes at 8.6% of total capital investment			4,611,900	29.51
Overheads				
Plant, 50% of conversion costs less utilities			1,165,600	7.46
Administrative, 10% of operating labor			53,200	0.34
Marketing, 10% of byproduct sales revenue			88,600	0.56
Total indirect costs			9,059,100	57.96
Gross average annual revenue requirements			16,515,200	105.67
Byproduct Sales Revenue				
Sulfur	15,100 tons	40.00/ton	(604,000)	3.87
Sodium sulfate	3,680 tons	23.00/ton	(84,600)	0.54
Spent anthracite	7,900 tons	25.00/ton	(197,500)	1.26
Net average annual revenue requirements			15,629,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.47	10.42	0.50	977

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 16,000 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $27,907,000; total depreciable investment, $52,330,000; and total capital investment, $53,627,000.
- All tons shown are 2,000 lb.

TABLE A-75

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: 2.0% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 53527000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4 & SP. ANT.	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	16000	15100	11600	36.00	21.93	21038600	798000	20240600	20240600
2	7000	31500000	1500000	16000	15100	11600	36.00	21.93	20738600	798000	19940600	40181200
3	7000	31500000	1500000	16000	15100	11600	36.00	21.93	20438600	798000	19640600	59821800
4	7000	31500000	1500000	16000	15100	11600	36.00	21.93	20138600	798000	19340600	79162400
5	7000	31500000	1500000	16000	15100	11600	36.00	21.93	19838600	798000	19040600	98203000
6	7000	31500000	1500000	16000	15100	11600	36.00	21.93	19538500	798000	18740500	116943500
7	7000	31500000	1500000	16000	15100	11600	36.00	21.93	19238500	798000	18440500	135384000
8	7000	31500000	1500000	16000	15100	11600	36.00	21.93	18938500	798000	18140500	153524500
9	7000	31500000	1500000	16000	15100	11600	36.00	21.93	18638500	798000	17840500	171365000
10	7000	31500000	1500000	16000	15100	11600	36.00	21.93	18338500	798000	17540500	188905500
11	5000	22500000	1071400	11400	10800	8300	36.00	21.93	15928800	570800	15358000	204263500
12	5000	22500000	1071400	11400	10800	8300	36.00	21.93	15628800	570800	15058000	219321500
13	5000	22500000	1071400	11400	10800	8300	36.00	21.93	15328800	570800	14758000	234079500
14	5000	22500000	1071400	11400	10800	8300	36.00	21.93	15028800	570800	14458000	248537500
15	5000	22500000	1071400	11400	10800	8300	36.00	21.93	14728800	570800	14158000	262695500
16	3500	15750000	750000	8000	7500	5800	36.00	21.93	12777400	397200	12380200	275075700
17	3500	15750000	750000	8000	7500	5800	36.00	21.93	12477300	397200	12080100	287155800
18	3500	15750000	750000	8000	7500	5800	36.00	21.93	12177300	397200	11780100	298935900
19	3500	15750000	750000	8000	7500	5800	36.00	21.93	11877300	397200	11480100	310416000
20	3500	15750000	750000	8000	7500	5800	36.00	21.93	11577300	397200	11180100	321596100
21	1500	6750000	321400	3400	3200	2500	36.00	21.93	8891000	170000	8721000	330317100
22	1500	6750000	321400	3400	3200	2500	36.00	21.93	8590900	170000	8420900	338738000
23	1500	6750000	321400	3400	3200	2500	36.00	21.93	8290900	170000	8120900	346858900
24	1500	6750000	321400	3400	3200	2500	36.00	21.93	7990900	170000	7820900	354679800
25	1500	6750000	321400	3400	3200	2500	36.00	21.93	7690900	170000	7520900	362200700
26	1500	6750000	321400	3400	3200	2500	36.00	21.93	7390900	170000	7220900	369421600
27	1500	6750000	321400	3400	3200	2500	36.00	21.93	7090800	170000	6920800	376342400
28	1500	6750000	321400	3400	3200	2500	36.00	21.93	6790800	170000	6620800	382963200
29	1500	6750000	321400	3400	3200	2500	36.00	21.93	6490800	170000	6320800	389284000
30	1500	6750000	321400	3400	3200	2500	36.00	21.93	6190800	170000	6020800	395306800
TOT	127500	573750000	27321000	291000	274500	211500			409824800	14520000	395304800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	15.00	0.53	14.47
MILLS PER KILOWATT-HOUR	6.43	0.23	6.20
CENTS PER MILLION BTU HEAT INPUT	71.43	2.53	68.90
DOLLARS PER TON OF SULFUR REMOVED	1408.33	49.89	1358.44
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	146908800	5664700	141244100

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	13.79	0.53	13.26
MILLS PER KILOWATT-HOUR	5.91	0.23	5.68
CENTS PER MILLION BTU HEAT INPUT	65.69	2.53	63.16
DOLLARS PER TON OF SULFUR REMOVED	1294.35	49.91	1244.44

TABLE A-76. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Base case: 500 MW, 3.5% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	12.0
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	12.0
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	13.5
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	7.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,307,000	22.9
Sulfur production (complete unit for sulfur production)	7,289,000	20.1
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	643,000	1.8
Subtotal	34,096,000	94.0
Services, utilities, and miscellaneous	2,046,000	5.6
Total excluding pond	36,142,000	99.6
Pond	154,000	0.4
Total direct investment	36,296,000	100.0
Indirect Investment		
Engineering design and supervision	2,352,000	6.5
Architect and engineering contractor	585,000	1.6
Construction expense	4,938,000	13.6
Contractor fees	1,472,000	4.1
Total indirect investment	9,347,000	25.8
Contingency	9,129,000	25.1
Total fixed investment	54,772,000	150.9
Other Capital Charges		
Allowance for startup and modifications	5,462,000	15.1
Interest during construction	6,573,000	18.1
Total depreciable investment	66,807,000	184.1
Land	44,000	0.1
Working capital	1,920,000	5.3
Total capital investment	68,771,000	189.5

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-77. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Base case: 500 MW, 3.5% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	3.08
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.23
Filter aid	70 tons	189.00/ton	13,200	0.06
Anthracite coal	33,180 tons	60.00/ton	1,990,800	9.43
Total raw materials cost			2,701,500	12.80
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.81
Utilities				
Fuel oil	793,800 gal	0.40/gal	317,500	1.50
Steam	1,569,400 MBtu	2.00/MBtu	3,138,800	14.87
Process water	4,024,300 kgal	0.12/kgal	482,900	2.29
Electricity	76,531,800 kWh	0.029/kWh	2,219,400	10.52
Heat credit	185,800 MBtu	2.00/MBtu	(371,600)	(1.76)
Maintenance				
Labor and material			2,173,100	10.30
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.68
Total conversion costs			8,698,400	41.21
Total direct costs			11,399,900	54.01
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,008,400	18.99
Average cost of capital and taxes at 8.6% of total capital investment			5,914,300	28.02
Overheads				
Plant, 50% of conversion costs less utilities			1,455,700	6.90
Administrative, 10% of operating labor			59,400	0.28
Marketing, 10% of byproduct sales revenue			192,400	0.91
Total indirect costs			11,630,200	55.10
Gross average annual revenue requirements			23,030,100	109.11
Byproduct Sales Revenue				
Sulfur	32,800 tons	40.00/ton	(1,312,000)	(6.22)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(0.87)
Spent anthracite	17,100 tons	25.00/ton	(427,500)	(2.02)
Net average annual revenue requirements			21,106,600	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton $ removed
Equivalent unit revenue requirements (net)	6.03	14.07	0.67	607

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $36,296,000; total depreciable investment, $66,807,000; and total capital investment, $68,771,000.
- All tons shown are 2,000 lb.

TABLE A-78

WELLMAN-LORD/ RESOX PROCESS BASE CASE: 500 MW 3.5% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 68771000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4 & SP. ANT.	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	32800	25100	36.00	21.93	28752200	1731200	27021000	27021000
2	7000	31500000	1500000	34800	32800	25100	36.00	21.93	28369200	1731200	26638000	53659000
3	7000	31500000	1500000	34800	32800	25100	36.00	21.93	27986200	1731200	26255000	79914000
4	7000	31500000	1500000	34800	32800	25100	36.00	21.93	27603100	1731200	25871900	105785900
5	7000	31500000	1500000	34800	32800	25100	36.00	21.93	27220100	1731200	25488900	131276800
6	7000	31500000	1500000	34800	32800	25100	36.00	21.93	26837100	1731200	25105900	156380700
7	7000	31500000	1500000	34800	32800	25100	36.00	21.93	26454100	1731200	24722900	181103600
8	7000	31500000	1500000	34800	32800	25100	36.00	21.93	26071000	1731200	24339800	205443400
9	7000	31500000	1500000	34800	32800	25100	36.00	21.93	25688000	1731200	23956800	229400200
10	7000	31500000	1500000	34800	32800	25100	36.00	21.93	25305000	1731200	23573800	252974000
11	5000	22500000	1071400	24800	23400	17900	36.00	21.93	21691800	1234900	20456900	273430900
12	5000	22500000	1071400	24800	23400	17900	36.00	21.93	21308800	1234900	20073900	293504800
13	5000	22500000	1071400	24800	23400	17900	36.00	21.93	20925800	1234900	19690900	313195700
14	5000	22500000	1071400	24800	23400	17900	36.00	21.93	20542800	1234900	19307900	332503600
15	5000	22500000	1071400	24800	23400	17900	36.00	21.93	20159700	1234900	18924800	351428400
16	3500	15750000	750000	17400	16400	12600	36.00	21.93	17266900	866700	16400200	367828600
17	3500	15750000	750000	17400	16400	12600	36.00	21.93	16883900	866700	16017200	383845800
18	3500	15750000	750000	17400	16400	12600	36.00	21.93	16500900	866700	15634200	399480000
19	3500	15750000	750000	17400	16400	12600	36.00	21.93	16117800	866700	15251100	414731100
20	3500	15750000	750000	17400	16400	12600	36.00	21.93	15734800	866700	14868100	429599200
21	1500	6750000	321400	7500	7000	5400	36.00	21.93	11775700	370400	11405300	441004500
22	1500	6750000	321400	7500	7000	5400	36.00	21.93	11392600	370400	11022200	452026700
23	1500	6750000	321400	7500	7000	5400	36.00	21.93	11009600	370400	10639200	462665900
24	1500	6750000	321400	7500	7000	5400	36.00	21.93	10626600	370400	10256200	472922100
25	1500	6750000	321400	7500	7000	5400	36.00	21.93	10243600	370400	9873200	482795300
26	1500	6750000	321400	7500	7000	5400	36.00	21.93	9860500	370400	9490100	492285400
27	1500	6750000	321400	7500	7000	5400	36.00	21.93	9477500	370400	9107100	501392500
28	1500	6750000	321400	7500	7000	5400	36.00	21.93	9094500	370400	8724100	510116600
29	1500	6750000	321400	7500	7000	5400	36.00	21.93	8711500	370400	8341100	518457700
30	1500	6750000	321400	7500	7000	5400	36.00	21.93	8328400	370400	7958000	526415700
TOT 127500		573750000	27321000	634000	597000	457500			557939700	31524000	526415700	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	20.42	1.15	19.27
MILLS PER KILOWATT-HOUR	8.75	0.49	8.26
CENTS PER MILLION BTU HEAT INPUT	97.24	5.49	91.75
DOLLARS PER TON OF SULFUR REMOVED	880.03	49.72	830.31
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	201015300	12289400	188725900

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	18.88	1.16	17.72
MILLS PER KILOWATT-HOUR	8.09	0.50	7.59
CENTS PER MILLION BTU HEAT INPUT	89.88	5.49	84.39
DOLLARS PER TON OF SULFUR REMOVED	813.83	49.76	764.07

TABLE A-79. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 5.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	561,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	10.1
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	10.1
Stack gas reheat (four indirect steam reheaters)	1,136,000	2.6
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	11.3
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	3,465,000	8.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	11,231,000	26.0
Sulfur production (complete unit for sulfur production)	9,811,000	22.7
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	840,000	1.9
Subtotal	40,666,000	94.0
Services, utilities, and miscellaneous	2,440,000	5.6
Total excluding pond	43,106,000	99.6
Pond	154,000	0.9
Total direct investment	43,260,000	100.0
Indirect Investment		
Engineering design and supervision	2,528,000	5.8
Architect and engineering contractor	629,000	1.5
Construction expense	5,711,000	13.2
Contractor fees	1,682,000	3.9
Total indirect investment	10,550,000	24.4
Contingency	10,762,000	24.9
Total fixed investment	64,572,000	149.3
Other Capital Charges		
Allowance for startup and modifications	6,442,000	14.9
Interest during construction	7,749,000	17.9
Total depreciable investment	78,763,000	182.1
Land	44,000	0.1
Working capital	2,564,000	5.9
Total capital investment	81,371,000	188.1

Basis
- Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
- Stack gas reheat to 175°F by indirect steam reheat.
- Minimum in-process storage; only pumps are spared.
- Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
- Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-80. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 5.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	9,690 tons	103.00/ton	998,100	3.83
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.19
Filter aid	110 tons	189.00/ton	20,800	0.08
Anthracite coal	51,030 tons	60.00/ton	3,061,800	11.76
Total raw materials cost			4,129,300	15.86
Conversion costs				
Operating labor and supervision	51,020 man-hr	12.50/man-hr	637,800	2.45
Utilities				
Fuel oil	1,220,900 gal	0.40/gal	488,400	1.87
Steam	2,189,700 MBtu	2.00/MBtu	4,379,400	16.81
Process water	6,087,400 kgal	0.12/kgal	730,500	2.80
Electricity	92,593,000 kWh	0.029/kWh	2,685,200	10.31
Heat credit	285,700 MBtu	2.00/MBtu	(571,400)	(2.19)
Maintenance				
Labor and material			2,591,000	9.95
Analyses	9,130 man-hr	17.00/man-hr	155,200	0.60
Total conversion costs			11,096,100	42.60
Total direct costs			15,225,400	58.46
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,725,800	18.15
Average cost of capital and taxes at 8.6% of total capital investment			6,997,900	26.87
Overheads				
Plant, 50% of conversion costs less utilities			1,692,000	6.50
Administrative, 10% of operating labor			63,800	0.24
Marketing, 10% of byproduct sales revenue			295,600	1.13
Total indirect costs			13,775,100	52.89
Gross average annual revenue requirements			29,000,500	111.35
Byproduct Sales Revenue				
Sulfur	50,400 tons	40.00/ton	(2,016,000)	(7.74)
Sodium sulfate	12,300 tons	23.00/ton	(282,900)	(1.09)
Spent anthracite	26,300 tons	25.00/ton	(657,500)	(2.52)
Net average annual revenue requirements			26,044,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	7.44	17.36	0.83	487

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 53,500 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $43,260,000; total depreciable investment, $78,763,000; and total capital investment, $81,371,000.
- All tons shown are 2,000 lb.

TABLE A-81

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: 5.0% S, REGULATED CO, ECONOMICS

TOTAL CAPITAL INVESTMENT 81371000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	53500	50400	38600	36.00	21.93	33703000	2660900	33042100	33042100
2	7000	31500000	1500000	53500	50400	38600	36.00	21.93	35251400	2660900	32590500	65632600
3	7000	31500000	1500000	53500	50400	38600	36.00	21.93	34799900	2660900	32139000	97771600
4	7000	31500000	1500000	53500	50400	38600	36.00	21.93	34348300	2660900	31687400	129459000
5	7000	31500000	1500000	53500	50400	38600	36.00	21.93	33896700	2660900	31235800	160694800
6	7000	31500000	1500000	53500	50400	38600	36.00	21.93	33445200	2660900	30784300	191479100
7	7000	31500000	1500000	53500	50400	38600	36.00	21.93	32993600	2660900	30332700	221811800
8	7000	31500000	1500000	53500	50400	38600	36.00	21.93	32542000	2660900	29881100	251692900
9	7000	31500000	1500000	53500	50400	38600	36.00	21.93	32090500	2660900	29429600	281122500
10	7000	31500000	1500000	53500	50400	38600	36.00	21.93	31638900	2660900	28978000	310100500
11	5000	22500000	1071400	38200	36000	27600	36.00	21.93	26868900	1901300	24967600	335068100
12	5000	22500000	1071400	38200	36000	27600	36.00	21.93	26417400	1901300	24516100	359584200
13	5000	22500000	1071400	38200	36000	27600	36.00	21.93	25965800	1901300	24064500	383648700
14	5000	22500000	1071400	38200	36000	27600	36.00	21.93	25514200	1901300	23612900	407261600
15	5000	22500000	1071400	38200	36000	27600	36.00	21.93	25062600	1901300	23161300	430422900
16	3500	15750000	750000	26800	25200	19300	36.00	21.93	21271000	1330400	19940600	450363500
17	3500	15750000	750000	26800	25200	19300	36.00	21.93	20819400	1330400	19489000	469852500
18	3500	15750000	750000	26800	25200	19300	36.00	21.93	20367800	1330400	19037400	488889900
19	3500	15750000	750000	26800	25200	19300	36.00	21.93	19916300	1330400	18585900	507475800
20	3500	15750000	750000	26800	25200	19300	36.00	21.93	19464700	1330400	18134300	525610100
21	1500	6750000	321400	11500	10800	8300	36.00	21.93	14292400	570800	13721600	539331700
22	1500	6750000	321400	11500	10800	8300	36.00	21.93	13840900	570800	13270100	552601800
23	1500	6750000	321400	11500	10800	8300	36.00	21.93	13389300	570800	12818500	565420300
24	1500	6750000	321400	11500	10800	8300	36.00	21.93	12937700	570800	12366900	577787200
25	1500	6750000	321400	11500	10800	8300	36.00	21.93	12486200	570800	11915400	589702600
26	1500	6750000	321400	11500	10800	8300	36.00	21.93	12034600	570800	11463800	601166400
27	1500	6750000	321400	11500	10800	8300	36.00	21.93	11583000	570800	11012200	612178600
28	1500	6750000	321400	11500	10800	8300	36.00	21.93	11131500	570800	10560700	622739300
29	1500	6750000	321400	11500	10800	8300	36.00	21.93	10679900	570800	10109100	632848400
30	1500	6750000	321400	11500	10800	8300	36.00	21.93	10228300	570800	9657500	642505900
TOT	127500	573750000	27321000	975000	918000	703500			690981400	48475500	642505900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	25.29	1.77	23.52
MILLS PER KILOWATT-HOUR	10.84	0.76	10.08
CENTS PER MILLION BTU HEAT INPUT	120.43	8.45	111.98
DOLLARS PER TON OF SULFUR REMOVED	708.70	49.72	658.98
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	249835500	18892900	230942600

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	23.46	1.77	21.69
MILLS PER KILOWATT-HOUR	10.05	0.76	9.29
CENTS PER MILLION BTU HEAT INPUT	111.71	8.45	103.26
DOLLARS PER TON OF SULFUR REMOVED	657.63	49.73	607.90

TABLE A-82. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	634,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	7,010,000	11.9
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	7,525,000	12.7
Stack gas reheat (four indirect steam reheaters)	1,846,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	8,232,000	13.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	4,088,000	6.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	13,499,000	22.9
Sulfur production (complete unit for sulfur production)	11,757,000	19.9
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	988,000	1.7
Subtotal	55,579,000	94.1
Services, utilities, and miscellaneous	3,335,000	5.7
Total excluding pond	58,914,000	99.8
Pond	127,000	0.2
Total direct investment	59,041,000	100.0
Indirect Investment		
Engineering design and supervision	2,892,000	4.9
Architect and engineering contractor	720,000	1.2
Construction expense	7,389,000	12.5
Contractor fees	2,130,000	3.6
Total indirect investment	13,131,000	22.2
Contingency	14,434,000	24.5
Total fixed investment	86,606,000	146.7
Other Capital Charges		
Allowance for startup and modifications	8,648,000	14.6
Interest during construction	10,393,000	17.6
Total depreciable investment	105,647,000	178.9
Land	69,000	0.1
Working capital	3,450,000	5.9
Total capital investment	109,166,000	184.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-83. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	12,600 tons	103.00/ton	1,297,800	3.64
Agricultural limestone	6,480 tons	15.00/ton	97,200	0.27
Filter aid	140 tons	189.00/ton	26,500	0.08
Anthracite coal	66,360 tons	60.00/ton	3,981,600	11.18
Total raw materials cost			5,403,100	15.17
Conversion costs				
Operating labor and supervision	67,180 man-hr	12.50/man-hr	839,800	2.36
Utilities				
Fuel oil	1,587,600 gal	0.40/gal	635,000	1.78
Steam	3,318,700 MBtu	2.00/MBtu	6,277,400	17.63
Process water	8,048,600 kgal	0.12/kgal	965,800	2.71
Electricity	152,464,000 kWh	0.028/kWh	4,269,000	11.99
Heat credit	371,500 MBtu	2.00/MBtu	(743,000)	(2.09)
Maintenance				
Labor and material			2,949,500	8.28
Analyses	13,810 man-hr	17.00/man-hr	234,800	0.66
Total conversion costs			15,428,300	43.32
Total direct costs			20,831,400	58.49
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			6,761,400	18.98
Average cost of capital and taxes at 8.6% of total capital investment			9,388,300	26.36
Overheads				
Plant, 50% of conversion costs less utilities			2,012,000	5.65
Administrative, 10% of operating labor			84,000	0.24
Marketing, 10% of byproduct sales revenue			384,700	1.08
Total indirect costs			18,630,400	52.31
Gross average annual revenue requirements			39,461,800	110.80
Byproduct Sales Revenue				
Sulfur	65,600 tons	40.00/ton	(2,624,000)	(7.37)
Sodium sulfate	16,000 tons	23.00/ton	(368,000)	(1.03)
Spent anthracite	34,200 tons	25.00/ton	(855,000)	(2.40)
Net average annual revenue requirements			35,614,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.09	11.87	0.57	512

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,999,900 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 69,560 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $59,041,000; total depreciable investment, $105,647,000; and total capital investment, $109,166,000.
- All tons shown are 2,000 lb.

TABLE A-84

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: 1300 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 109166000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4 & SP. ANT.	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	63000000	3000000	69600	65600	50200	36.00	21.93	49170200	3462500	45707700	45707700
7	7000	63000000	3000000	69600	65600	50200	36.00	21.93	48443300	3462500	44980800	90688500
8	7000	63000000	3000000	69600	65600	50200	36.00	21.93	47716400	3462500	44253900	134942400
9	7000	63000000	3000000	69600	65600	50200	36.00	21.93	46989600	3462500	43527100	178469500
10	7000	63000000	3000000	69600	65600	50200	36.00	21.93	46262700	3462500	42800200	221269700
11	5000	45000000	2142900	49700	46900	35900	36.00	21.93	39616300	2475700	37140600	258410300
12	5000	45000000	2142900	49700	46900	35900	36.00	21.93	38889400	2475700	36413700	294824000
13	5000	45000000	2142900	49700	46900	35900	36.00	21.93	38162600	2475700	35686900	330510900
14	5000	45000000	2142900	49700	46900	35900	36.00	21.93	37435700	2475700	34960000	365470900
15	5000	45000000	2142900	49700	46900	35900	36.00	21.93	36708900	2475700	34233200	399704100
16	3500	31500000	1500000	34800	32800	25100	36.00	21.93	31422900	1731200	29691700	429395800
17	3500	31500000	1500000	34800	32800	25100	36.00	21.93	30696000	1731200	28964800	458360600
18	3500	31500000	1500000	34800	32800	25100	36.00	21.93	29969200	1731200	28238000	486598600
19	3500	31500000	1500000	34800	32800	25100	36.00	21.93	29242300	1731200	27511100	514109700
20	3500	31500000	1500000	34800	32800	25100	36.00	21.93	28515500	1731200	26784300	540894000
21	1500	13500000	642900	14900	14100	10800	36.00	21.93	21394500	744400	20650100	561544100
22	1500	13500000	642900	14900	14100	10800	36.00	21.93	20667700	744400	19923300	581467400
23	1500	13500000	642900	14900	14100	10800	36.00	21.93	19940800	744400	19196400	600663800
24	1500	13500000	642900	14900	14100	10800	36.00	21.93	19214000	744400	18469600	619133400
25	1500	13500000	642900	14900	14100	10800	36.00	21.93	18487100	744400	17742700	636876100
26	1500	13500000	642900	14900	14100	10800	36.00	21.93	17760300	744400	17015900	653892000
27	1500	13500000	642900	14900	14100	10800	36.00	21.93	17033400	744400	16289000	670181000
28	1500	13500000	642900	14900	14100	10800	36.00	21.93	16306500	744400	15562100	685743100
29	1500	13500000	642900	14900	14100	10800	36.00	21.93	15579700	744400	14835300	700578400
30	1500	13500000	642900	14900	14100	10800	36.00	21.93	14852800	744400	14108400	714686800
TOT	92500	832500000	39643500	919500	867500	664000			760477800	45791000	714686800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	19.18	1.15	18.03
MILLS PER KILOWATT-HOUR	8.22	0.49	7.73
CENTS PER MILLION BTU HEAT INPUT	91.35	5.50	85.85
DOLLARS PER TON OF SULFUR REMOVED	827.06	49.80	777.26

PROCESS COST DISCOUNTED AT 11.64 TO INITIAL YEAR, DOLLARS 312284400 20740400 291544000

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	17.38	1.15	16.23
MILLS PER KILOWATT-HOUR	7.45	0.49	6.96
CENTS PER MILLION BTU HEAT INPUT	82.78	5.49	77.29
DOLLARS PER TON OF SULFUR REMOVED	749.42	49.77	699.65

TABLE A-85. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	624,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	6,853,000	11.9
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	7,324,000	12.7
Stack gas reheat (four indirect steam reheaters)	1,802,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	8,026,000	13.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	4,001,000	7.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	13,175,000	22.8
Sulfur production (complete unit for sulfur production)	11,487,000	19.9
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	968,000	1.7
Subtotal	54,260,000	94.1
Services, utilities, and miscellaneous	3,256,000	5.6
Total excluding pond	57,516,000	99.7
Pond	159,000	0.3
Total direct investment	57,675,000	100.0
Indirect Investment		
Engineering design and supervision	2,876,000	5.0
Architect and engineering contractor	716,000	1.2
Construction expense	7,249,000	12.6
Contractor fees	2,092,000	3.6
Total indirect investment	12,933,000	22.4
Contingency	14,122,000	24.5
Total fixed investment	84,730,000	146.9
Other Capital Charges		
Allowance for startup and modifications	8,457,000	14.7
Interest during construction	10,168,000	17.6
Total depreciable investment	103,355,000	179.2
Land	72,000	0.1
Working capital	3,349,000	5.8
Total capital investment	106,776,000	185.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-86. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW new)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	12,200 tons	103.00/ton	1,256,600	3.66
Agricultural limestone	6,260 tons	15.00/ton	93,900	0.27
Filter aid	135 tons	189.00/ton	25,500	0.08
Anthracite coal	64,150 tons	60.00/ton	3,849,000	11.22
Total raw materials cost			5,225,000	15.23
Conversion costs				
Operating labor and supervision	67,180 man-hr	12.50/man-hr	839,800	2.45
Utilities				
Fuel oil	1,534,700 gal	0.40/gal	613,900	1.79
Steam	3,034,000 MBtu	2.00/MBtu	6,068,000	17.69
Process water	7,780,200 kgal	0.12/kgal	933,600	2.72
Electricity	147,399,000 kWh	0.028/kWh	4,127,200	12.03
Heat credit	359,100 MBtu	2.00/MBtu	(718,200)	(2.09)
Maintenance				
Labor and material			2,880,600	8.40
Analyses	13,810 man-hr	17.00/man-hr	234,800	0.68
Total conversion costs			14,979,700	43.67
Total direct costs			20,204,700	58.90
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			6,201,300	18.08
Average cost of capital and taxes at 8.6% of total capital investment			9,182,700	26.77
Overheads				
Plant, 50% of conversion costs less utilities			1,977,600	5.77
Administrative, 10% of operating labor			84,000	0.24
Marketing, 10% of byproduct sales revenue			371,900	1.08
Total indirect costs			17,817,500	51.94
Gross average annual revenue requirements			38,022,200	110.84
Byproduct Sales Revenue				
Sulfur	63,400 tons	40.00/ton	(2,536,000)	(7.39)
Sodium sulfate	15,470 tons	23.00/ton	(355,800)	(1.04)
Spent anthracite	33,100 tons	25.00/ton	(827,500)	(2.41)
Net average annual revenue requirements			34,302,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.90	11.83	0.56	510

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 67,240 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $57,565,000; total depreciable investment, $103,355,000; and total capital investment, $106,776,000.
- All tons shown are 2,000 lb.

TABLE A-87

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: 1000 MW, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 106776000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67200	63400	48600	36.00	21.93	46833500	3348200	43485300	43485300
2	7000	60900000	2900000	67200	63400	48600	36.00	21.93	46240900	3348200	42892700	86378000
3	7000	60900000	2900000	67200	63400	48600	36.00	21.93	45648300	3348200	42300100	128678100
4	7000	60900000	2900000	67200	63400	48600	36.00	21.93	45055700	3348200	41707500	170385600
5	7000	60900000	2900000	67200	63400	48600	36.00	21.93	44463200	3348200	41115000	211500600
6	7000	60900000	2900000	67200	63400	48600	36.00	21.93	43870600	3348200	40522400	252023000
7	7000	60900000	2900000	67200	63400	48600	36.00	21.93	43278000	3348200	39929800	291952800
8	7000	60900000	2900000	67200	63400	48600	36.00	21.93	42685500	3348200	39337300	331290100
9	7000	60900000	2900000	67200	63400	48600	36.00	21.93	42092900	3348200	38744700	370034800
10	7000	60900000	2900000	67200	63400	48600	36.00	21.93	41500300	3348200	38152100	408186900
11	5000	43500000	2071400	48000	45300	34700	36.00	21.93	35166400	2391800	32774600	440961500
12	5000	43500000	2071400	48000	45300	34700	36.00	21.93	34573900	2391800	32182100	473143600
13	5000	43500000	2071400	48000	45300	34700	36.00	21.93	33981300	2391800	31589500	504733100
14	5000	43500000	2071400	48000	45300	34700	36.00	21.93	33388700	2391800	30996900	535730000
15	5000	43500000	2071400	48000	45300	34700	36.00	21.93	32796100	2391800	30404300	566134300
16	3500	30450000	1450000	33600	31700	24300	36.00	21.93	27780400	1674100	26106300	592240600
17	3500	30450000	1450000	33600	31700	24300	36.00	21.93	27187800	1674100	25513700	617754300
18	3500	30450000	1450000	33600	31700	24300	36.00	21.93	26595200	1674100	24921100	642675400
19	3500	30450000	1450000	33600	31700	24300	36.00	21.93	26002600	1674100	24328500	667003900
20	3500	30450000	1450000	33600	31700	24300	36.00	21.93	25410100	1674100	23736000	690739900
21	1500	13050000	621400	14400	13600	10400	36.00	21.93	18609900	717700	17892200	708632100
22	1500	13050000	621400	14400	13600	10400	36.00	21.93	18017300	717700	17299600	725931700
23	1500	13050000	621400	14400	13600	10400	36.00	21.93	17424700	717700	16707000	742638700
24	1500	13050000	621400	14400	13600	10400	36.00	21.93	16832200	717700	16114500	758753200
25	1500	13050000	621400	14400	13600	10400	36.00	21.93	16239600	717700	15521900	774275100
26	1500	13050000	621400	14400	13600	10400	36.00	21.93	15647000	717700	14929300	789204400
27	1500	13050000	621400	14400	13600	10400	36.00	21.93	15054400	717700	14336700	803541100
28	1500	13050000	621400	14400	13600	10400	36.00	21.93	14461900	717700	13744200	817285300
29	1500	13050000	621400	14400	13600	10400	36.00	21.93	13869300	717700	13151600	830436900
30	1500	13050000	621400	14400	13600	10400	36.00	21.93	13276700	717700	12559000	842995900
TOT	127500	1109250000	52821000	1224000	1155000	885000			903984400	60988500	842995900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	17.11	1.15	15.96
MILLS PER KILOWATT-HOUR	7.09	0.48	6.61
CENTS PER MILLION BTU HEAT INPUT	81.50	5.50	76.00
DOLLARS PER TON OF SULFUR REMOVED	738.55	49.83	688.72

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 327446000 23771700 303674300

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	15.90	1.15	14.75
MILLS PER KILOWATT-HOUR	6.59	0.48	6.11
CENTS PER MILLION BTU HEAT INPUT	75.73	5.50	70.23
DOLLARS PER TON OF SULFUR REMOVED	686.33	49.83	636.50

TABLE A-88. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	487,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	11.5
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	11.4
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.0
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	12.8
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,868,000	7.5
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	9,104,000	23.8
Sulfur production (complete unit for sulfur production)	7,974,000	20.9
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	697,000	1.8
Subtotal	35,888,000	94.0
Services, utilities, and miscellaneous	2,153,000	5.6
Total excluding pond	38,041,000	99.6
Pond	154,000	0.4
Total direct investment	38,195,000	100.0
Indirect Investment		
Engineering design and supervision	2,399,000	6.2
Architect and engineering contractor	597,000	1.6
Construction expense	5,151,000	13.5
Contractor fees	1,530,000	4.0
Total indirect investment	9,677,000	25.3
Contingency	9,574,000	25.1
Total fixed investment	57,446,000	150.4
Other Capital Charges		
Allowance for startup and modifications	5,729,000	15.0
Interest during construction	6,894,000	18.0
Total depreciable investment	70,069,000	183.4
Land	44,000	0.1
Working capital	2,085,000	5.5
Total capital investment	72,198,000	189.0

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-89. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	7,180 tons	103.00/ton	739,500	3.30
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.22
Filter aid	80 tons	189.00/ton	15,100	0.06
Anthracite coal	37,800 tons	60.00/ton	2,268,000	10.13
Total raw materials cost			3,071,200	13.71
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.65
Utilities				
Fuel oil	904,300 gal	0.40/gal	361,700	1.62
Steam	1,729,800 MBtu	2.00/MBtu	3,459,600	15.45
Process water	4,558,000 kgal	0.12/kgal	547,000	2.44
Electricity	80,687,000 kWh	0.029/kWh	2,339,900	10.45
Heat credit	211,600 MBtu	2.00/MBtu	(423,200)	(1.89)
Maintenance				
Labor and material			2,287,100	10.21
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.65
Total conversion costs			9,310,400	41.58
Total direct costs			12,381,600	55.29
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,204,100	18.77
Average cost of capital and taxes at 8.6% of total capital investment			6,209,000	27.73
Overheads				
Plant, 50% of conversion costs less utilities			1,512,700	6.76
Administrative, 10% of operating labor			59,400	0.26
Marketing, 10% of byproduct sales revenue			219,300	0.98
Total indirect costs			12,204,500	54.50
Gross average annual revenue requirements			24,586,100	109.79
Byproduct Sales Revenue				
Sulfur	37,400 tons	40.00/ton	(1,496,000)	(6.68)
Sodium sulfate	9,110 tons	23.00/ton	(209,500)	(0.93)
Spent anthracite	19,500 tons	25.00/ton	(487,500)	(2.18)
Net average annual revenue requirements			22,393,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.40	14.93	0.71	565

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 39,620 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $38,195,000; total depreciable investment, $70,069,000; and total capital investment, $72,198,000.
- All tons shown are 2,000 lb.

TABLE A-90

WELLMAN-LORD/ RESUX PROCESS VARIATION FROM BASE CASE: 90% S REMOVAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 72198000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	39600	37400	28600	36.00	21.93	30576100	1973600	28602500	28602500
2	7000	31500000	1500000	39600	37400	28600	36.00	21.93	30174300	1973600	28200700	56803200
3	7000	31500000	1500000	39600	37400	28600	36.00	21.93	29772600	1973600	27799000	84602200
4	7000	31500000	1500000	39600	37400	28600	36.00	21.93	29370900	1973600	27397300	111999500
5	7000	31500000	1500000	39600	37400	28600	36.00	21.93	28969200	1973600	26995600	138995100
6	7000	31500000	1500000	39600	37400	28600	36.00	21.93	28567400	1973600	26593800	165588900
7	7000	31500000	1500000	39600	37400	28600	36.00	21.93	28165700	1973600	26192100	191781000
8	7000	31500000	1500000	39600	37400	28600	36.00	21.93	27764000	1973600	25790400	217571400
9	7000	31500000	1500000	39600	37400	28600	36.00	21.93	27362300	1973600	25388700	242960100
10	7000	31500000	1500000	39600	37400	28600	36.00	21.93	26960500	1973600	24986900	267947000
11	5000	22500000	1071400	28300	26700	20400	36.00	21.93	23049300	1408600	21640700	289587700
12	5000	22500000	1071400	28300	26700	20400	36.00	21.93	22647600	1408600	21239000	310826700
13	5000	22500000	1071400	28300	26700	20400	36.00	21.93	22245900	1408600	20837300	331664000
14	5000	22500000	1071400	28300	26700	20400	36.00	21.93	21844200	1408600	20435600	352099600
15	5000	22500000	1071400	28300	26700	20400	36.00	21.93	21442400	1408600	20033800	372133400
16	3500	15750000	750000	19800	18700	14300	36.00	21.93	18318300	986800	17331500	389464900
17	3500	15750000	750000	19800	18700	14300	36.00	21.93	17916600	986800	16929800	406394700
18	3500	15750000	750000	19800	18700	14300	36.00	21.93	17514900	986800	16528100	422922800
19	3500	15750000	750000	19800	18700	14300	36.00	21.93	17113100	986800	16126300	439049100
20	3500	15750000	750000	19800	18700	14300	36.00	21.93	16711400	986800	15726600	454775700
21	1500	6750000	321400	8500	8000	6100	36.00	21.93	12440500	421800	12018700	466792400
22	1500	6750000	321400	8500	8000	6100	36.00	21.93	12038800	421800	11617000	478409400
23	1500	6750000	321400	8500	8000	6100	36.00	21.93	11637000	421800	11215200	489624600
24	1500	6750000	321400	8500	8000	6100	36.00	21.93	11235300	421800	10813500	500438100
25	1500	6750000	321400	8500	8000	6100	36.00	21.93	10833600	421800	10411800	510849900
26	1500	6750000	321400	8500	8000	6100	36.00	21.93	10431900	421800	10010100	520860000
27	1500	6750000	321400	8500	8000	6100	36.00	21.93	10030200	421800	9608400	530468400
28	1500	6750000	321400	8500	8000	6100	36.00	21.93	9628400	421800	9206600	539675000
29	1500	6750000	321400	8500	8000	6100	36.00	21.93	9226700	421800	8804900	548479900
30	1500	6750000	321400	8500	8000	6100	36.00	21.93	8825000	421800	8403200	556883100
TOT	127500	573750000	27321000	721500	681000	520500			592814100	35931000	556883100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	21.70	1.32	20.38
MILLS PER KILOWATT-HOUR	9.30	0.56	8.74
CENTS PER MILLION BTU HEAT INPUT	103.32	6.26	97.06
DOLLARS PER TON OF SULFUR REMOVED	821.64	49.80	771.84

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 213808800 14010000 199798800

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	20.08	1.32	18.76
MILLS PER KILOWATT-HOUR	8.60	0.56	8.04
CENTS PER MILLION BTU HEAT INPUT	95.60	6.26	89.34
DOLLARS PER TON OF SULFUR REMOVED	760.34	49.82	710.52

TABLE A-91. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: oil-fired, existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, nd pumps)	311,000	1.5
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	3,908,000	18.2
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,213,000	19.6
Stack gas reheat (four direct oil-fired reheaters)	1,063,000	4.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,577,000	7.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,685,000	21.8
Sulfur production (complete unit for sulfur production)	4,140,000	19.2
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	387,000	1.8
Subtotal	20,284,000	94.3
Services, utilities, and miscellaneous	1,217,000	5.7
Total direct investment	21,501,000	100.0
Indirect Investment		
Engineering design and supervision	1,937,000	9.0
Architect and engineering contractor	484,000	2.3
Construction expense	3,191,000	14.8
Contractor fees	988,000	4.6
Total indirect investment	6,600,000	30.7
Contingency	5,620,000	26.1
Total fixed investment	33,721,000	156.8
Other Capital Charges		
Allowance for startup and modifications	3,372,000	15.7
Interest during construction	4,047,000	18.8
Total depreciable investment	41,140,000	191.3
Land	28,000	0.1
Working capital	1,156,000	5.4
Total capital investment	42,324,000	196.8

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-92. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: oil-fired, existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,780 tons	103.00/ton	286,300	2.12
Agricultural limestone	2,740 tons	15.00/ton	41,100	0.31
Filter aid	31 tons	189.00/ton	5,900	0.04
Anthracite coal	14,630 tons	60.00/ton	877,800	6.50
Total raw materials cost			1,211,100	8.97
Conversion costs				
Operating labor and supervision	45,440 man-hr	12.50/man-hr	568,000	4.21
Utilities				
Fuel oil	2,799,400 gal	0.40/gal	1,119,800	8.29
Steam	508,200 MBtu	2.00/MBtu	1,016,400	7.53
Process water	1,851,200 kgal	0.12/kgal	222,100	1.64
Electricity	52,790,000 kWh	0.029/kWh	1,530,900	11.34
Heat credit	81,900 MBtu	2.00/MBtu	(163,800)	(1.21)
Maintenance				
Labor and material			1,290,100	9.56
Analyses	8,130 man-hr	17.00/man-hr	138,200	1.02
Total conversion costs			5,721,700	42.38
Total direct costs			6,932,800	51.35
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			2,633,000	19.50
Average cost of capital and taxes at 8.6% of total capital investment			3,639,900	26.96
Overheads				
Plant, 50% of conversion costs less utilities			998,200	7.40
Administrative, 10% of operating labor			56,800	0.42
Marketing, 10% of byproduct sales revenue			84,500	0.63
Total indirect costs			7,412,400	54.91
Gross average annual revenue requirements			14,345,200	106.26
Byproduct Sales Revenue				
Sulfur	14,400 tons	40.00/ton	(576,000)	(4.27)
Sodium sulfate	3,530 tons	23.00/ton	(81,200)	(0.60)
Spent anthracite	7,500 tons	25.00/ton	(187,500)	(1.39)
Net average annual revenue requirements			13,500,500	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.86	2.52	0.42	881

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Oil burned, 5,350,000 bbl/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 15,330 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $21,501,000; total depreciable investment, $41,140,000; and total capital investment, $42,324,000.
- All tons shown are 2,000 lb.

TABLE A-93

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: OIL FIRED EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 42324000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	32200000	5324100	15300	14400	11000	36.00	21.93	18174900	759600	17415300	17415300
7	7000	32200000	5324100	15300	14400	11000	36.00	21.93	17891900	759600	17132300	34547600
8	7000	32200000	5324100	15300	14400	11000	36.00	21.93	17608800	759600	16849200	51396800
9	7000	32200000	5324100	15300	14400	11000	36.00	21.93	17325800	759600	16566200	67963000
10	7000	32200000	5324100	15300	14400	11000	36.00	21.93	17042800	759600	16283200	84246200
11	5000	23000000	3802900	11000	10300	7900	36.00	21.93	14795400	544000	14251400	98497600
12	5000	23000000	3802900	11000	10300	7900	36.00	21.93	14512400	544000	13968400	112466000
13	5000	23000000	3802900	11000	10300	7900	36.00	21.93	14229300	544000	13685300	126151300
14	5000	23000000	3802900	11000	10300	7900	36.00	21.93	13946300	544000	13402300	139553600
15	5000	23000000	3802900	11000	10300	7900	36.00	21.93	13663200	544000	13119200	152672800
16	3500	16100000	2662000	7700	7200	5500	36.00	21.93	11848000	379800	11468200	164141000
17	3500	16100000	2662000	7700	7200	5500	36.00	21.93	11565000	379800	11185200	175326200
18	3500	16100000	2662000	7700	7200	5500	36.00	21.93	11281900	379800	10902100	186228300
19	3500	16100000	2662000	7700	7200	5500	36.00	21.93	10998900	379800	10619100	196847400
20	3500	16100000	2662000	7700	7200	5500	36.00	21.93	10715800	379800	10336000	207183400
21	1500	6900000	1140900	3300	3100	2400	36.00	21.93	8232300	164200	8068100	215251500
22	1500	6900000	1140900	3300	3100	2400	36.00	21.93	7949200	164200	7785000	223036500
23	1500	6900000	1140900	3300	3100	2400	36.00	21.93	7666200	164200	7502000	230538500
24	1500	6900000	1140900	3300	3100	2400	36.00	21.93	7383200	164200	7219000	237757500
25	1500	6900000	1140900	3300	3100	2400	36.00	21.93	7100100	164200	6935900	244693400
26	1500	6900000	1140900	3300	3100	2400	36.00	21.93	6817100	164200	6652900	251346300
27	1500	6900000	1140900	3300	3100	2400	36.00	21.93	6534000	164200	6369800	257716100
28	1500	6900000	1140900	3300	3100	2400	36.00	21.93	6251000	164200	6086800	263802900
29	1500	6900000	1140900	3300	3100	2400	36.00	21.93	5967900	164200	5803700	269606600
30	1500	6900000	1140900	3300	3100	2400	36.00	21.93	5684900	164200	5520700	275127300
TOT	92500	425500000	70354000	203000	190500	146000			285186300	10059000	275127300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER BARREL OF OIL BURNED	4.05	0.14	3.91
MILLS PER KILOWATT-HOUR	6.17	0.22	5.95
CENTS PER MILLION BTU HEAT INPUT	67.02	2.36	64.66
DOLLARS PER TON OF SULFUR REMOVED	1404.86	49.55	1355.31
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	116156600	4552900	111603700

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER BARREL OF OIL BURNED	3.64	0.14	3.50
MILLS PER KILOWATT-HOUR	5.54	0.21	5.33
CENTS PER MILLION BTU HEAT INPUT	60.25	2.37	57.88
DOLLARS PER TON OF SULFUR REMOVED	1265.32	49.59	1215.73

TABLE A-94. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: alternate conversion in sulfur production unit)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	11.6
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	11.6
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.0
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	13.0
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	7.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,976,000	23.9
Sulfur production (complete unit for sulfur production)	7,906,000	21.0
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	643,000	1.7
Subtotal	35,382,000	94.0
Services, utilities, and miscellaneous	2,123,000	5.6
Total excluding pond	37,505,000	99.6
Pond	154,000	0.4
Total direct investment	37,659,000	100.0
Indirect Investment		
Engineering design and supervision	2,395,000	6.4
Architect and engineering contractor	595,000	1.6
Construction expense	5,091,000	13.5
Contractor fees	1,513,000	4.0
Total indirect investment	9,594,000	25.5
Contingency	9,451,000	25.1
Total fixed investment	56,704,000	150.6
Other Capital Charges		
Allowance for startup and modifications	5,655,000	15.0
Interest during construction	6,804,000	18.1
Total depreciable investment	69,163,000	183.7
Land	44,000	0.1
Working capital	2,033,000	5.4
Total capital investment	71,240,000	189.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-95. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: alternate conversion in sulfur production unit)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	2.93
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.22
Filter aid	70 tons	189.00/ton	13,200	0.06
Anthracite coal	37,330 tons	60.00/ton	2,239,800	10.12
Total raw materials cost			2,950,500	13.33
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.68
Utilities				
Fuel oil	893,000 gal	0.40/gal	357,200	1.61
Steam	1,676,900 MBtu	2.00/MBtu	3,353,800	15.15
Process water	4,472,900 kgal	0.12/kgal	536,700	2.42
Electricity	79,757,100 kWh	0.029/kWh	2,313,000	10.45
Heat credit	209,000 MBtu	2.00/MBtu	(418,000)	(1.89)
Maintenance				
Labor and material			2,254,900	10.19
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.65
Total conversion costs			9,135,900	41.26
Total direct costs			12,086,400	54.59
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,149,800	18.74
Average cost of capital and taxes at 8.6% of total capital investment			6,126,600	27.67
Overheads				
Plant, 50% of conversion costs less utilities			1,496,600	6.76
Administrative, 10% of operating labor			59,400	0.27
Marketing, 10% of byproduct sales revenue			197,600	0.89
Total indirect costs			12,030,000	54.33
Gross average annual revenue requirements			24,116,400	108.92
Byproduct Sales Revenue				
Sulfur	32,800 tons	40.00/ton	(1,312,000)	5.92
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	0.83
Spent anthracite	19,200 tons	25.00/ton	(480,000)	2.17
Net average annual revenue requirements			22,140,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.33	14.76	0.70	637

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $37,659,000; total depreciable investment, $69,163,000; and total capital investment, $71,240,000.
- All tons shown are 2,000 lb.

TABLE A-96

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: LOW CONVERSION, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 71240000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: NA2SO4 & SP. ANT.	NET REVENUE, $/TON: SULFUR	NET REVENUE, $/TON: NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	32800	27200	36.00	21.97	30045700	1778400	28267300	28267300
2	7000	31500000	1500000	34800	32800	27200	36.00	21.97	29649200	1778400	27870800	56138100
3	7000	31500000	1500000	34800	32800	27200	36.00	21.97	29252600	1778400	27474200	83612300
4	7000	31500000	1500000	34800	32800	27200	36.00	21.97	28856100	1778400	27077700	110690000
5	7000	31500000	1500000	34800	32800	27200	36.00	21.97	28459600	1778400	26681200	137371200
6	7000	31500000	1500000	34800	32800	27200	36.00	21.97	28063000	1778400	26284600	163655800
7	7000	31500000	1500000	34800	32800	27200	36.00	21.97	27666500	1778400	25888100	189543900
8	7000	31500000	1500000	34800	32800	27200	36.00	21.97	27270000	1778400	25491600	215035500
9	7000	31500000	1500000	34800	32800	27200	36.00	21.97	26873400	1778400	25095000	240130500
10	7000	31500000	1500000	34800	32800	27200	36.00	21.97	26476900	1778400	24698500	264829000
11	5000	22500000	1071400	24800	23400	19400	36.00	21.97	22655000	1268600	21386400	286215400
12	5000	22500000	1071400	24800	23400	19400	36.00	21.97	22258500	1268600	20989900	307205300
13	5000	22500000	1071400	24800	23400	19400	36.00	21.97	21861900	1268600	20593300	327798600
14	5000	22500000	1071400	24800	23400	19400	36.00	21.97	21465400	1268600	20196800	347995400
15	5000	22500000	1071400	24800	23400	19400	36.00	21.97	21068900	1268600	19800300	367795700
16	3500	15750000	750000	17400	16400	13600	36.00	21.97	18013700	889200	17124500	384920200
17	3500	15750000	750000	17400	16400	13600	36.00	21.97	17617200	889200	16728000	401648200
18	3500	15750000	750000	17400	16400	13600	36.00	21.97	17220700	889200	16331500	417979700
19	3500	15750000	750000	17400	16400	13600	36.00	21.97	16824200	889200	15935000	433914700
20	3500	15750000	750000	17400	16400	13600	36.00	21.97	16427600	889200	15538400	449453100
21	1500	6750000	321400	7500	7000	5800	36.00	21.97	12245800	379400	11870400	461323500
22	1500	6750000	321400	7500	7000	5800	36.00	21.97	11853300	379400	11473900	472797400
23	1500	6750000	321400	7500	7000	5800	36.00	21.97	11456700	379400	11077300	483874700
24	1500	6750000	321400	7500	7000	5800	36.00	21.97	11060200	379400	10680800	494555500
25	1500	6750000	321400	7500	7000	5800	36.00	21.97	10663700	379400	10284300	504839800
26	1500	6750000	321400	7500	7000	5800	36.00	21.97	10267200	379400	9887800	514727600
27	1500	6750000	321400	7500	7000	5800	36.00	21.97	9870600	379400	9491200	524218800
28	1500	6750000	321400	7500	7000	5800	36.00	21.97	9474100	379400	9094700	533313500
29	1500	6750000	321400	7500	7000	5800	36.00	21.97	9077600	379400	8698200	542011700
30	1500	6750000	321400	7500	7000	5800	36.00	21.97	8681000	379400	8301600	550313300
TOT	127500	573750000	27321000	634000	597000	495000			582680300	32367000	550313300	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	21.33	1.19	20.14
MILLS PER KILOWATT-HOUR	9.14	0.51	8.63
CENTS PER MILLION BTU HEAT INPUT	101.56	5.64	95.92
DOLLARS PER TON OF SULFUR REMOVED	919.05	51.05	868.00

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 210085100 12623100 197462000

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	19.73	1.19	18.54
MILLS PER KILOWATT-HOUR	8.45	0.50	7.95
CENTS PER MILLION BTU HEAT INPUT	93.94	5.65	88.29
DOLLARS PER TON OF SULFUR REMOVED	850.55	51.11	799.44

TABLE A-97. WELLMAN-LORD/RESOX PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: wet-scrubbing fly ash removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,642,000	14.5
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	13.6
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.5
Fly ash removal (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,296,000	16.5
ESP credit	(4,713,000)	(14.7)
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	8.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,307,000	26.0
Sulfur production (complete unit for sulfur production)	7,289,000	22.8
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	643,000	2.0
Subtotal	30,051,000	93.9
Services, utilities, and miscellaneous	1,803,000	5.6
Total excluding pond	31,854,000	99.5
Pond	154,000	0.5
Total direct investment	32,008,000	100.0
Indirect Investment		
Engineering design and supervision	2,352,000	7.3
Architect and engineering contractor	585,000	1.8
Construction expense	4,449,000	13.9
Contractor fees	1,337,000	4.2
Total indirect investment	8,723,000	27.2
Contingency	8,146,000	25.5
Total fixed investment	48,877,000	152.7
Other Capital Charges		
Allowance for startup and modifications	4,872,000	15.2
Interest during construction	5,865,000	18.3
Total depreciable investment	59,614,000	186.2
Land	44,000	0.1
Working capital	1,983,000	6.2
Total capital investment	61,641,000	192.5

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-98. WELLMAN-LORD/RESOX PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: wet-scrubbing fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	3.16
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.24
Filter aid	70 tons	189.00/ton	13,200	0.06
Anthracite coal	33,180 tons	60.00/ton	1,990,800	9.70
Total raw materials cost			2,701,500	13.16
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.89
Utilities				
Fuel oil	793,800 gal	0.40/gal	317,500	1.55
Steam	1,569,400 MBtu	2.00/MBtu	3,138,800	15.29
Process water	4,024,300 kgal	0.12/kgal	482,900	2.35
Electricity	113,085,800 kWh	0.029/kWh	3,279,500	15.97
Heat credit	185,800 MBtu	2.00/MBtu	(371,600)	(1.81)
ESP electricity credit	7,114,900 kWh	0.029/kWh	(206,300)	(1.00)
Maintenance				
Labor and material			1,915,900	9.33
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.70
Total conversion costs			9,295,000	45.27
Total direct costs			11,996,500	58.43
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,576,800	17.42
Average cost of capital and taxes at 8.6% of total capital investment			5,301,100	25.82
Overheads				
Plant, 50% of conversion costs less utilities			1,327,100	6.47
Administrative, 10% of operating labor			59,400	0.29
Marketing, 10% of byproduct sales revenue			192,400	0.94
Total indirect costs			10,456,800	50.94
Gross average annual revenue requirements			22,453,300	109.37
Byproduct Sales Revenue				
Sulfur	32,800 tons	40.00/ton	(1,312,000)	(6.39)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(0.90)
Spent anthracite	17,100 tons	25.00/ton	(427,500)	(2.08)
Net average annual revenue requirements			20,529,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.87	13.69	0.65	590

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $32,008,000; total depreciable investment, $59,614,000; and total capital investment, $61,641,000.
- All tons shown are 2,000 lb.

TABLE A-99

WELLMAN-LORD/ RESOX PROCESS VARIATION FROM BASE CASE: WET SCRUBBING FLY ASH REMOVAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 61641000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR NA2SO4 & SP. ANT.	NET REVENUE, $/TON SULFUR	NET REVENUE, $/TON NA2SO4 & SP. ANT.	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	32800	25100	36.00	21.93	27562300	1731200	25831100	25831100
2	7000	31500000	1500000	34800	32800	25100	36.00	21.93	27220500	1731200	25489300	51320400
3	7000	31500000	1500000	34800	32800	25100	36.00	21.93	26878700	1731200	25147500	76467900
4	7000	31500000	1500000	34800	32800	25100	36.00	21.93	26536900	1731200	24805700	101273600
5	7000	31500000	1500000	34800	32800	25100	36.00	21.93	26195100	1731200	24463900	125737500
6	7000	31500000	1500000	34800	32800	25100	36.00	21.93	25853300	1731200	24122100	149859600
7	7000	31500000	1500000	34800	32800	25100	36.00	21.93	25511600	1731200	23780400	173640000
8	7000	31500000	1500000	34800	32800	25100	36.00	21.93	25169800	1731200	23438600	197078600
9	7000	31500000	1500000	34800	32800	25100	36.00	21.93	24828000	1731200	23096800	220175400
10	7000	31500000	1500000	34800	32800	25100	36.00	21.93	24486200	1731200	22755000	242930400
11	5000	22500000	1071400	24800	23400	17900	36.00	21.93	20740600	1234900	19505700	262436100
12	5000	22500000	1071400	24800	23400	17900	36.00	21.93	20398900	1234900	19164000	281600100
13	5000	22500000	1071400	24800	23400	17900	36.00	21.93	20057100	1234900	18822200	300422300
14	5000	22500000	1071400	24800	23400	17900	36.00	21.93	19715300	1234900	18480400	318902700
15	5000	22500000	1071400	24800	23400	17900	36.00	21.93	19373500	1234900	18138600	337041300
16	3500	15750000	750000	17400	16400	12600	36.00	21.93	16399900	866700	15533200	352574500
17	3500	15750000	750000	17400	16400	12600	36.00	21.93	16058200	866700	15191500	367766000
18	3500	15750000	750000	17400	16400	12600	36.00	21.93	15716400	866700	14849700	382615700
19	3500	15750000	750000	17400	16400	12600	36.00	21.93	15374600	866700	14507900	397123600
20	3500	15750000	750000	17400	16400	12600	36.00	21.93	15032800	866700	14166100	411289700
21	1500	6750000	321400	7500	7000	5400	36.00	21.93	10972300	370400	10601900	421891600
22	1500	6750000	321400	7500	7000	5400	36.00	21.93	10630500	370400	10260100	432151700
23	1500	6750000	321400	7500	7000	5400	36.00	21.93	10288800	370400	9918400	442070100
24	1500	6750000	321400	7500	7000	5400	36.00	21.93	9947000	370400	9576600	451646700
25	1500	6750000	321400	7500	7000	5400	36.00	21.93	9605200	370400	9234800	460881500
26	1500	6750000	321400	7500	7000	5400	36.00	21.93	9263400	370400	8893000	469774500
27	1500	6750000	321400	7500	7000	5400	36.00	21.93	8921600	370400	8551200	478325700
28	1500	6750000	321400	7500	7000	5400	36.00	21.93	8579900	370400	8209500	486535200
29	1500	6750000	321400	7500	7000	5400	36.00	21.93	8238100	370400	7867700	494402900
30	1500	6750000	321400	7500	7000	5400	36.00	21.93	7896300	370400	7525900	501928800
TOT	127500	573750000	27321000	634000	597000	457500			533452800	31524000	501928800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	19.53	1.16	18.37
MILLS PER KILOWATT-HOUR	8.37	0.50	7.87
CENTS PER MILLION BTU HEAT INPUT	92.98	5.50	87.48
DOLLARS PER TON OF SULFUR REMOVED	841.41	49.72	791.69

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 192994300 12289500 180704800

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	18.12	1.15	16.97
MILLS PER KILOWATT-HOUR	7.77	0.50	7.27
CENTS PER MILLION BTU HEAT INPUT	86.30	5.50	80.80
DOLLARS PER TON OF SULFUR REMOVED	781.35	49.75	731.60

TABLE A-100. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	305,000	1.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	1,952,000	10.0
SO_2 absorption (two absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	1,902,000	9.8
Stack gas reheat (two indirect steam reheaters)	504,000	2.6
Chloride purge (two chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	2,153,000	11.1
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,534,000	7.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,455,000	22.9
Sulfur production (complete unit for sulfur production)	5,062,000	26.1
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	374,000	1.9
Subtotal	18,241,000	93.9
Services, utilities, and miscellaneous	1,094,000	5.6
Total excluding pond	19,335,000	99.5
Pond	96,000	0.5
Total direct investment	19,431,000	100.0
Indirect Investment		
Engineering design and supervision	1,671,000	8.6
Architect and engineering contractor	415,000	2.2
Construction expense	2,940,000	15.1
Contractor fees	915,000	4.7
Total indirect investment	5,941,000	30.6
Contingency	5,074,000	26.1
Total fixed investment	30,446,000	156.7
Other Capital Charges		
Allowance for startup and modifications	3,035,000	15.6
Interest during construction	3,654,000	18.8
Total depreciable investment	37,135,000	191.1
Land	15,000	0.1
Working capital	844,000	4.3
Total capital investment	37,994,000	195.5

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-101. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,660 tons	103.00/ton	274,000	2.43
Catalyst			1,700	0.02
Agricultural limestone	1,370 tons	15.00/ton	20,600	0.18
Filter aid	30 tons	189.00/ton	5,700	0.05
Coal	12,300 tons	25.00/ton	307,500	2.73
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			610,900	5.42
Conversion costs				
Operating labor and supervision	30,040 man-hr	12.50/man-hr	375,500	3.33
Utilities				
Fuel oil	180,300 gal	0.40/gal	72,100	0.64
Steam	663,200 MBtu	2.00/MBtu	1,326,400	11.76
Process water	1,800,400 kgal	0.12/kgal	216,000	1.91
Electricity	33,096,000 kWh	0.031/kWh	1,026,000	9.10
Heat credit	24,800 MBtu	2.00/MBtu	(49,600)	(0.44)
Maintenance				
Labor and material			1,356,300	12.03
Analyses	4,480 man-hr	17.00/man-hr	76,200	0.68
Total conversion costs			4,398,900	39.01
Total direct costs			5,009,800	44.43
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 7.0% of total depreciable investment			2,599,500	23.05
Average cost of capital and taxes at 8.6% of total capital investment			3,267,500	28.98
Overheads				
Plant, 50% of conversion costs less utilities			904,000	8.02
Administrative, 10% of operating labor			37,600	0.33
Marketing, 10% of byproduct sales revenue			60,200	0.53
Total indirect costs			6,868,800	60.91
Gross average annual revenue requirements			11,878,600	105.34
Byproduct Sales Revenue				
Sulfur	13,100 tons	40.00/ton	(524,000)	(4.65)
Sodium sulfate	3,380 tons	23.00/ton	(77,700)	(0.69)
Net average annual revenue requirements			11,276,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	8.05	17.80	0.85	768

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 20 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 633,500 tons/yr, 9,500 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 14,680 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $19,431,000; total depreciable investment, $37,135,000; and total capital investment, $37,994,000.
- All tons shown are 2,000 lb.

TABLE A-102

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 200 MW EXISTING REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 37994000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11	5000	9500000	452400	10500	9400	2400	36.00	20.70	14292400	388100	13904300	13904300
12	5000	9500000	452400	10500	9400	2400	36.00	20.70	13973000	388100	13584900	27489200
13	5000	9500000	452400	10500	9400	2400	36.00	20.70	13653600	388100	13265500	40754700
14	5000	9500000	452400	10500	9400	2400	36.00	20.70	13334300	388100	12946200	53700900
15	5000	9500000	452400	10500	9400	2400	36.00	20.70	13014900	388100	12626800	66327700
16	3500	6650000	316700	7300	6500	1700	36.00	20.70	11581800	269200	11312600	77640300
17	3500	6650000	316700	7300	6500	1700	36.00	20.70	11262500	269200	10993300	88633600
18	3500	6650000	316700	7300	6500	1700	36.00	20.70	10943100	269200	10673900	99307500
19	3500	6650000	316700	7300	6500	1700	36.00	20.70	10623700	269200	10354500	109662000
20	3500	6650000	316700	7300	6500	1700	36.00	20.70	10304300	269200	10035100	119697100
21	1500	2850000	135700	3100	2800	700	36.00	20.70	8355900	115300	8240600	127937700
22	1500	2850000	135700	3100	2800	700	36.00	20.70	8036500	115300	7921200	135858900
23	1500	2850000	135700	3100	2800	700	36.00	20.70	7717100	115300	7601800	143460700
24	1500	2850000	135700	3100	2800	700	36.00	20.70	7397800	115300	7282500	150743200
25	1500	2850000	135700	3100	2800	700	36.00	20.70	7078400	115300	6963100	157706300
26	1500	2850000	135700	3100	2800	700	36.00	20.70	6759000	115300	6643700	164350000
27	1500	2850000	135700	3100	2800	700	36.00	20.70	6439700	115300	6324400	170674400
28	1500	2850000	135700	3100	2800	700	36.00	20.70	6120300	115300	6005000	176679400
29	1500	2850000	135700	3100	2800	700	36.00	20.70	5800900	115300	5685600	182365000
30	1500	2850000	135700	3100	2800	700	36.00	20.70	5481500	115300	5366200	187731200
TOT	57500	109250000	5202900	120000	107500	27500			192170700	4439500	187731200	
LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST												
DOLLARS PER TON OF COAL BURNED									36.94	0.86	36.08	
MILLS PER KILOWATT-HOUR									16.71	0.39	16.32	
CENTS PER MILLION BTU HEAT INPUT									175.90	4.06	171.84	
DOLLARS PER TON OF SULFUR REMOVED									1601.42	36.99	1564.43	
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS									86930600	2200200	84730400	
LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT												
DOLLARS PER TON OF COAL BURNED									33.78	0.85	32.93	
MILLS PER KILOWATT-HOUR									15.28	0.38	14.90	
CENTS PER MILLION BTU HEAT INPUT									160.87	4.07	156.80	
DOLLARS PER TON OF SULFUR REMOVED									1461.02	36.98	1424.04	

TABLE A-103. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 200 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	301,000	1.6
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	1,908,000	10.0
SO_2 absorption (two absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	1,858,000	9.7
Stack gas reheat (two indirect steam reheaters)	493,000	2.6
Chloride purge (two chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	2,104,000	11.0
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,503,000	7.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,357,000	22.8
Sulfur production (complete unit for sulfur production)	4,972,000	26.0
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	367,000	1.9
Subtotal	17,863,000	93.5
Services, utilities, and miscellaneous	1,072,000	5.6
Total excluding pond	18,935,000	99.1
Pond	175,000	0.9
Total direct investment	19,110,000	100.0
Indirect Investment		
Engineering design and supervision	1,673,000	8.7
Architect and engineering contractor	415,000	2.2
Construction expense	2,902,000	15.2
Contractor fees	904,000	4.7
Total indirect investment	5,894,000	30.8
Contingency	5,001,000	26.2
Total fixed investment	30,005,000	157.0
Other Capital Charges		
Allowance for startup and modifications	2,983,000	15.6
Interest during construction	3,601,000	18.9
Total depreciable investment	36,589,000	191.5
Land	15,000	0.1
Working capital	824,000	4.3
Total capital investment	37,428,000	195.9

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-104. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 200 MW new)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,580 tons	103.00/ton	265,700	2.48
Catalyst			1,600	0.02
Agricultural limestone	1,320 tons	15.00/ton	19,800	0.19
Filter aid	29 tons	189.00/ton	5,500	0.05
Coal	11,900 tons	25.00/ton	297,500	2.78
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			591,500	5.53
Conversion costs				
Operating labor and supervision	30,040 man-hr	12.50/man-hr	375,500	3.51
Utilities				
Fuel oil	174,600 gal	0.40/gal	69,800	0.65
Steam	642,300 MBtu	2.00/MBtu	1,284,600	12.00
Process water	1,743,600 kgal	0.12/kgal	209,200	1.96
Electricity	32,072,400 kWh	0.031/kWh	994,200	9.29
Heat credit	24,000 MBtu	2.00/MBtu	(48,000)	(0.45)
Maintenance				
Labor and material			1,330,700	12.44
Analyses	4,480 man-hr	17.00/man-hr	76,200	0.71
Total conversion costs			4,292,200	40.11
Total direct costs			4,883,700	45.64
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			2,195,300	20.51
Average cost of capital and taxes at 8.6% of total capital investment			3,218,800	30.08
Overheads				
Plant, 50% of conversion costs less utilities			891,200	8.33
Administrative, 10% of operating labor			37,600	0.35
Marketing, 10% of byproduct sales revenue			58,300	0.55
Total indirect costs			6,401,200	59.82
Gross average annual revenue requirements			11,284,900	105.46
Byproduct Sales Revenue				
Sulfur	12,700 tons	40.00/ton	(508,000)	(4.75)
Sodium sulfate	3,270 tons	23.00/ton	(75,200)	(0.71)
Net average annual revenue requirements			10,701,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton $ removed
Equivalent unit revenue requirements (net)	7.64	17.43	0.83	753

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 613,200 tons/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 14,220 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $19,110,000; total depreciable investment, $36,589,000; and total capital investment, $37,428,000.
- All tons shown are 2,000 lb.

TABLE A-105

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 200 MW, REGULATED CO, ECONOMICS

TOTAL CAPITAL INVESTMENT 37428000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/YR	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	12880000	613300	14200	12700	3300	36.00	20.70	14445500	525500	13920000	13920000
2	7000	12880000	613300	14200	12700	3300	36.00	20.70	14235700	525500	13710200	27630200
3	7000	12880000	613300	14200	12700	3300	36.00	20.70	14026000	525500	13500500	41130700
4	7000	12880000	613300	14200	12700	3300	36.00	20.70	13816200	525500	13290700	54421400
5	7000	12880000	613300	14200	12700	3300	36.00	20.70	13606400	525500	13080900	67502300
6	7000	12880000	613300	14200	12700	3300	36.00	20.70	13396700	525500	12871200	80373500
7	7000	12880000	613300	14200	12700	3300	36.00	20.70	13186900	525500	12661400	93034900
8	7000	12880000	613300	14200	12700	3300	36.00	20.70	12977100	525500	12451600	105486500
9	7000	12880000	613300	14200	12700	3300	36.00	20.70	12767300	525500	12241800	117728300
10	7000	12880000	613300	14200	12700	3300	36.00	20.70	12557600	525500	12032100	129760400
11	5000	9200000	438100	10200	9100	2300	36.00	20.70	10971100	375200	10595900	140527700
12	5000	9200000	438100	10200	9100	2300	36.00	20.70	10761300	375200	10386100	150913800
13	5000	9200000	438100	10200	9100	2300	36.00	20.70	10551600	375200	10176400	161090200
14	5000	9200000	438100	10200	9100	2300	36.00	20.70	10341800	375200	9966600	171056800
15	5000	9200000	438100	10200	9100	2300	36.00	20.70	10132000	375200	9756800	180813600
16	3500	6440000	306700	7100	6300	1600	36.00	20.70	8836000	259900	8576100	189389700
17	3500	6440000	306700	7100	6300	1600	36.00	20.70	8626300	259900	8366400	197756100
18	3500	6440000	306700	7100	6300	1600	36.00	20.70	8416500	259900	8156600	205912700
19	3500	6440000	306700	7100	6300	1600	36.00	20.70	8206700	259900	7946800	213859500
20	3500	6440000	306700	7100	6300	1600	36.00	20.70	7997000	259900	7737100	221596600
21	1500	2760000	131400	3000	2700	700	36.00	20.70	6196900	111700	6085200	227681800
22	1500	2760000	131400	3000	2700	700	36.00	20.70	5987100	111700	5875400	233557200
23	1500	2760000	131400	3000	2700	700	36.00	20.70	5777300	111700	5665600	239222800
24	1500	2760000	131400	3000	2700	700	36.00	20.70	5567600	111700	5455900	244678700
25	1500	2760000	131400	3000	2700	700	36.00	20.70	5357800	111700	5246100	249924800
26	1500	2760000	131400	3000	2700	700	36.00	20.70	5148000	111700	5036300	254961100
27	1500	2760000	131400	3000	2700	700	36.00	20.70	4938300	111700	4826600	259787700
28	1500	2760000	131400	3000	2700	700	36.00	20.70	4728500	111700	4616800	264404500
29	1500	2760000	131400	3000	2700	700	36.00	20.70	4518700	111700	4407000	268811500
30	1500	2760000	131400	3000	2700	700	36.00	20.70	4309000	111700	4197300	273008800
TOT	127500	234600000	11171000	258500	231000	59500			282384900	9376100	273008800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	25.28	0.84	24.44
MILLS PER KILOWATT-HOUR	11.07	0.36	10.71
CENTS PER MILLION BTU HEAT INPUT	120.37	4.00	116.37
DOLLARS PER TON OF SULFUR REMOVED	1092.40	36.27	1056.13

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 100914900 3671000 97243900

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	23.18	0.85	22.33
MILLS PER KILOWATT-HOUR	10.15	0.37	9.78
CENTS PER MILLION BTU HEAT INPUT	110.36	4.02	106.34
DOLLARS PER TON OF SULFUR REMOVED	1001.14	36.42	964.72

TABLE A-106. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 500 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	463,000	1.2
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,442,000	11.8
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,426,000	11.7
Stack gas reheat (four indirect steam reheaters)	1,153,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,977,000	13.2
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,678,000	7.1
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,266,000	21.9
Sulfur production (complete unit for sulfur production)	8,236,000	21.8
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	648,000	1.7
Subtotal	35,289,000	93.5
Services, utilities, and miscellaneous	2,117,000	5.6
Total excluding pond	37,406,000	99.1
Pond	357,000	0.9
Total direct investment	37,763,000	100.0
Indirect Investment		
Engineering design and supervision	2,434,000	6.5
Architect and engineering contractor	603,000	1.6
Construction expense	5,107,000	13.5
Contractor fees	1,516,000	4.0
Total indirect investment	9,660,000	25.6
Contingency	9,485,000	25.1
Total fixed investment	56,908,000	150.7
Other Capital Charges		
Allowance for startup and modifications	5,655,000	15.0
Interest during construction	6,829,000	18.1
Total depreciable investment	69,392,000	183.8
Land	39,000	0.1
Working capital	1,736,000	4.6
Total capital investment	71,167,000	188.5

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-107. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 500 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,440 tons	103.00/ton	663,300	3.10
Catalyst			4,100	0.02
Agricultural limestone	3,310 tons	15.00/ton	49,700	0.23
Filter aid	72 tons	189.00/ton	13,600	0.06
Coal	29,790 tons	25.00/ton	744,800	3.49
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			1,476,900	6.91
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.78
Utilities				
Fuel oil	436,600 gal	0.40/gal	174,600	0.82
Steam	1,605,800 MBtu	2.00/MBtu	3,211,600	15.03
Process water	4,358,900 kgal	0.12/kgal	523,100	2.45
Electricity	79,277,100 kWh	0.029/kWh	2,299,000	10.76
Heat credit	60,000 MBtu	2.00/MBtu	(120,000)	(0.56)
Maintenance				
Labor and material			2,255,100	10.55
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.68
Total conversion costs			9,081,700	42.51
Total direct costs			10,558,600	49.42
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			4,441,100	20.79
Average cost of capital and taxes at 8.6% of total capital investment			6,120,400	28.65
Overheads				
Plant, 50% of conversion costs less utilities			1,496,700	7.00
Administrative, 10% of operating labor			59,400	0.28
Marketing, 10% of byproduct sales revenue			145,600	0.68
Total indirect costs			12,263,200	57.40
Gross average annual revenue requirements			22,821,800	106.82
Byproduct Sales Revenue				
Sulfur	31,700 tons	40.00/ton	(1,268,000)	(5.94)
Sodium sulfate	8,180 tons	23.00/ton	(188,100)	(0.88)
Net average annual revenue requirements			21,365,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.10	13.93	0.66	601

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,533,350 tons/yr, 9,200 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 35,550 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $37,763,000; total depreciable investment, $69,392,000; and total capital investment, $71,167,000.
- All tons shown are 2,000 lb.

TABLE A-108

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 500 MW EXISTING, REGULATED CO.ECONOMICS

TOTAL CAPITAL INVESTMENT 71167000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	32200000	1533300	35600	31700	8200	36.00	20.70	29259400	1310900	27948500	27948500
7	7000	32200000	1533300	35600	31700	8200	36.00	20.70	28782000	1310900	27471100	55419600
8	7000	32200000	1533300	35600	31700	8200	36.00	20.70	28304600	1310900	26993700	82413300
9	7000	32200000	1533300	35600	31700	8200	36.00	20.70	27827200	1310900	26516300	108929600
10	7000	32200000	1533300	35600	31700	8200	36.00	20.70	27349700	883000	26666700	135596300
11	5000	23000000	1095200	25400	22600	5800	36.00	20.70	23865200	933700	22949500	158545800
12	5000	23000000	1095200	25400	22600	5800	36.00	20.70	23405800	933700	22472100	180817900
13	5000	23000000	1095200	25400	22600	5800	36.00	20.70	22928400	933700	21994700	202812600
14	5000	23000000	1095200	25400	22600	5800	36.00	20.70	22451000	933700	21517300	224329900
15	5000	23000000	1095200	25400	22600	5800	36.00	20.70	21973500	933700	21039800	245369700
16	3500	16100000	766700	17800	15900	4100	36.00	20.70	19165000	657300	18507700	263877400
17	3500	16100000	766700	17800	15900	4100	36.00	20.70	18687600	657300	18030300	281907700
18	3500	16100000	766700	17800	15900	4100	36.00	20.70	18210200	657300	17552900	299460600
19	3500	16100000	766700	17800	15900	4100	36.00	20.70	17732800	657300	17075500	316536100
20	3500	16100000	766700	17800	15900	4100	36.00	20.70	17255300	657300	16598000	333136100
21	1500	6900000	328600	7600	6800	1800	36.00	20.70	13433200	282100	13151100	346287200
22	1500	6900000	328600	7600	6800	1800	36.00	20.70	12955800	282100	12673700	358958900
23	1500	6900000	328600	7600	6800	1800	36.00	20.70	12478400	282100	12196300	371155200
24	1500	6900000	328600	7600	6800	1800	36.00	20.70	12001000	282100	11718900	382874100
25	1500	6900000	328600	7600	6800	1800	36.00	20.70	11523500	282100	11241400	396115500
26	1500	6900000	328600	7600	6800	1800	36.00	20.70	11046100	282100	10764000	406879500
27	1500	6900000	328600	7600	6800	1800	36.00	20.70	10568700	282100	10286600	419166100
28	1500	6900000	328600	7600	6800	1800	36.00	20.70	10091300	282100	9809200	424975300
29	1500	6900000	328600	7600	6800	1800	36.00	20.70	9613900	282100	9331800	434307100
30	1500	6900000	328600	7600	6800	1800	36.00	20.70	9136600	282100	8854300	443161400
TOT	92500	425500000	20262000	470000	419000	108500			460064000	16902600	443161400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	22.71	0.84	21.87
MILLS PER KILOWATT-HOUR	9.95	0.37	9.58
CENTS PER MILLION BTU HEAT INPUT	108.12	3.97	104.15
DOLLARS PER TON OF SULFUR REMOVED	978.86	35.96	942.90
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	187087100	7600200	179486900

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	20.38	0.83	19.55
MILLS PER KILOWATT-HOUR	8.93	0.37	8.56
CENTS PER MILLION BTU HEAT INPUT	97.03	3.94	93.09
DOLLARS PER TON OF SULFUR REMOVED	877.93	35.66	842.27

TABLE A-109. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 2.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	318,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	15.1
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	15.0
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.9
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	16.8
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,619,000	5.5
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,732,000	16.3
Sulfur production (complete unit for sulfur production)	5,306,000	18.3
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	395,000	1.4
Subtotal	27,128,000	93.4
Services, utilities, and miscellaneous	1,628,000	5.6
Total excluding pond	28,756,000	99.0
Pond	280,000	1.0
Total direct investment	29,036,000	100.0
Indirect Investment		
Engineering design and supervision	2,224,000	7.7
Architect and engineering contractor	551,000	1.9
Construction expense	4,107,000	14.1
Contractor fees	1,242,000	4.3
Total indirect investment	8,124,000	28.0
Contingency	7,432,000	25.6
Total fixed investment	44,592,000	153.6
Other Capital Charges		
Allowance for startup and modifications	4,431,000	15.3
Interest during construction	5,351,000	18.4
Total depreciable investment	54,374,000	187.3
Land	42,000	0.1
Working capital	1,162,000	4.0
Total capital investment	55,578,000	191.4

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-110. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 2.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,900 tons	103.00/ton	298,700	1.90
Catalyst			1,800	0.01
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.31
Filter aid	32 tons	189.00/ton	6,000	0.04
Coal	13,410 tons	25.00/ton	335,300	2.13
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			691,800	4.40
Conversion costs				
Operating labor and supervision	42,550 man-hr	12.50/man-hr	531,900	3.38
Utilities				
Fuel oil	196,500 gal	0.40/gal	78,600	0.50
Steam	946,600 MBtu	2.00/MBtu	1,893,200	12.04
Process water	2,064,700 kgal	0.12/kgal	247,800	1.58
Electricity	60,894,000 kWh	0.029/kWh	1,765,900	11.24
Heat credit	27,000 MBtu	2.00/MBtu	(54,000)	(0.34)
Maintenance				
Labor and material			1,733,800	11.03
Analyses	7,610 man-hr	17.00/man-hr	129,400	0.82
Total conversion costs			6,326,600	40.25
Total direct costs			7,018,400	44.65
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,262,400	20.75
Average cost of capital and taxes at 8.6% of total capital investment			4,779,700	30.40
Overheads				
Plant, 50% of conversion costs less utilities			1,197,600	7.62
Administrative, 10% of operating labor			53,200	0.34
Marketing, 10% of byproduct sales revenue			65,700	0.42
Total indirect costs			9,358,600	59.53
Gross average annual revenue requirements			16,377,000	104.18
Byproduct Sales Revenue				
Sulfur	14,300 tons	40.00/ton	(572,000)	(3.64)
Sodium sulfate	3,680 tons	23.00/ton	(84,600)	(0.54)
Net average annual revenue requirements			15,720,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.49	10.48	0.50	982

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 16,000 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $29,036,000; total depreciable investment, $54,374,000; and total capital investment, $55,578,000.
- All tons shown are 2,000 lb.

TABLE A-111

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 2.0% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 55578000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	16000	14300	3700	36.00	20.70	21091300	591400	20499900	20499900
2	7000	31500000	1500000	16000	14300	3700	36.00	20.70	20779600	591400	20188200	40688100
3	7000	31500000	1500000	16000	14300	3700	36.00	20.70	20467800	591400	19876400	60564500
4	7000	31500000	1500000	16000	14300	3700	36.00	20.70	20156100	591400	19564700	80129200
5	7000	31500000	1500000	16000	14300	3700	36.00	20.70	19844300	591400	19252900	99382100
6	7000	31500000	1500000	16000	14300	3700	36.00	20.70	19532600	591400	18941200	118323300
7	7000	31500000	1500000	16000	14300	3700	36.00	20.70	19220800	591400	18629400	136952700
8	7000	31500000	1500000	16000	14300	3700	36.00	20.70	18909100	591400	18317700	155270400
9	7000	31500000	1500000	16000	14300	3700	36.00	20.70	18597300	591400	18005900	173276300
10	7000	31500000	1500000	16000	14300	3700	22.50	20.70	18285600	398400	17887200	191163500
11	5000	22500000	1071400	11400	10200	2600	36.00	20.70	15990100	421000	15569100	206732600
12	5000	22500000	1071400	11400	10200	2600	36.00	20.70	15678400	421000	15257400	221990000
13	5000	22500000	1071400	11400	10200	2600	36.00	20.70	15366600	421000	14945600	236935600
14	5000	22500000	1071400	11400	10200	2600	36.00	20.70	15054900	421000	14633900	251569500
15	5000	22500000	1071400	11400	10200	2600	36.00	20.70	14743100	421000	14322100	265891600
16	3500	15750000	750000	8000	7200	1800	36.00	20.70	12872300	296500	12575800	278467400
17	3500	15750000	750000	8000	7200	1800	36.00	20.70	12560500	296500	12264000	290731400
18	3500	15750000	750000	8000	7200	1800	36.00	20.70	12248800	296500	11952300	302683700
19	3500	15750000	750000	8000	7200	1800	36.00	20.70	11937000	296500	11640500	314324200
20	3500	15750000	750000	8000	7200	1800	36.00	20.70	11625300	296500	11328800	325653000
21	1500	6750000	321400	3400	3100	800	36.00	20.70	9045200	128200	8917000	334570000
22	1500	6750000	321400	3400	3100	800	36.00	20.70	8733500	128200	8605300	343175300
23	1500	6750000	321400	3400	3100	800	36.00	20.70	8421700	128200	8293500	351468800
24	1500	6750000	321400	3400	3100	800	36.00	20.70	8110000	128200	7981800	359450600
25	1500	6750000	321400	3400	3100	800	36.00	20.70	7798200	128200	7670000	367120600
26	1500	6750000	321400	3400	3100	800	36.00	20.70	7486500	128200	7358300	374478900
27	1500	6750000	321400	3400	3100	800	36.00	20.70	7174700	128200	7046500	381525400
28	1500	6750000	321400	3400	3100	800	36.00	20.70	6863000	128200	6734800	388260200
29	1500	6750000	321400	3400	3100	800	36.00	20.70	6551200	128200	6423000	394683200
30	1500	6750000	321400	3400	3100	800	36.00	20.70	6239500	128200	6111300	400794500
TOT	127500	573750000	27321000	291000	261000	67000			411385000	10590500	400794500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	15.06	0.39	14.67
MILLS PER KILOWATT-HOUR	6.45	0.16	6.29
CENTS PER MILLION BTU HEAT INPUT	71.70	1.84	69.86
DOLLARS PER TON OF SULFUR REMOVED	1413.69	36.39	1377.30
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	147140600	4134200	143006400

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	13.82	0.39	13.43
MILLS PER KILOWATT-HOUR	5.92	0.17	5.75
CENTS PER MILLION BTU HEAT INPUT	65.79	1.85	63.94
DOLLARS PER TON OF SULFUR REMOVED	1296.39	36.42	1259.97

TABLE A-112. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Base case: 500 MW, 3.5% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	11.7
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	11.7
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	13.1
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	7.1
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,144,000	21.8
Sulfur production (complete unit for sulfur production)	8,138,000	21.8
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	639,000	1.7
Subtotal	34,778,000	93.3
Services, utilities, and miscellaneous	2,087,000	5.6
Total excluding pond	36,865,000	98.9
Pond	425,000	1.1
Total direct investment	37,290,000	100.0
Indirect Investment		
Engineering design and supervision	2,432,000	6.5
Architect and engineering contractor	602,000	1.6
Construction expense	5,055,000	13.6
Contractor fees	1,502,000	4.0
Total indirect investment	9,591,000	25.7
Contingency	9,376,000	25.1
Total fixed investment	56,257,000	150.8
Other Capital Charges		
Allowance for startup and modifications	5,583,000	15.0
Interest during construction	6,751,000	18.1
Total depreciable investment	68,591,000	183.9
Land	42,000	0.1
Working capital	1,705,000	4.6
Total capital investment	70,338,000	188.6

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-113. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Base case: 500 MW, 3.5% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	3.12
Catalyst			4,000	0.02
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.23
Filter aid	70 tons	189.00/ton	13,200	0.06
Coal	29,140 tons	25.00/ton	728,500	3.51
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			1,444,600	6.95
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.86
Utilities				
Fuel oil	427,100 gal	0.40/gal	170,800	0.82
Steam	1,570,900 MBtu	2.00/MBtu	3,141,800	15.11
Process water	4,264,200 kgal	0.12/kgal	511,700	2.46
Electricity	77,568,400 kWh	0.029/kWh	2,249,500	10.82
Heat credit	58,700 MBtu	2.00/MBtu	(117,400)	(0.56)
Maintenance				
Labor and material			2,224,600	10.70
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.70
Total conversion costs			8,919,300	42.91
Total direct costs			10,363,900	49.86
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,115,500	19.80
Average cost of capital and taxes at 8.6% of total capital investment			6,049,100	29.10
Overheads				
Plant, 50% of conversion costs less utilities			1,481,400	7.13
Administrative, 10% of operating labor			59,400	0.28
Marketing, 10% of byproduct sales revenue			142,400	0.68
Total indirect costs			11,847,800	56.99
Gross average annual revenue requirements			22,211,700	106.85
Byproduct Sales Revenue				
Sulfur	31,000 tons	40.00/ton	(1,240,000)	(5.96)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(0.89)
Net average annual revenue requirements			20,787,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.94	13.86	0.66	598

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $37,290,000; total depreciable investment, $68,591,000; and total capital investment, $70,538,000.
- All tons shown are 2,000 lb.

TABLE A-114

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS BASE CASE 500 MW 3.5% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 70338000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	31000	8000	36.00	20.70	28118700	1281600	26837100	26837100
2	7000	31500000	1500000	34800	31000	8000	36.00	20.70	27725500	1281600	26443900	53281000
3	7000	31500000	1500000	34800	31000	8000	36.00	20.70	27332200	1281600	26050600	79331600
4	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26939000	1281600	25657400	104989000
5	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26545700	1281600	25264100	130253100
6	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26152400	1281600	24870800	155123900
7	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25759200	1281600	24477600	179601500
8	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25365900	1281600	24084300	203685800
9	7000	31500000	1500000	34800	31000	8000	36.00	20.70	24972600	1281600	23691000	227376800
10	7000	31500000	1500000	34800	31000	8000	22.50	20.70	24579400	863100	23716300	251093100
11	5000	22500000	1071400	24800	22100	5700	36.00	20.70	21252400	913600	20338800	271431900
12	5000	22500000	1071400	24800	22100	5700	36.00	20.70	20859200	913600	19945600	291377500
13	5000	22500000	1071400	24800	22100	5700	36.00	20.70	20465900	913600	19552300	310929800
14	5000	22500000	1071400	24800	22100	5700	36.00	20.70	20072600	913600	19159000	330088800
15	5000	22500000	1071400	24800	22100	5700	36.00	20.70	19679400	913600	18765800	348854600
16	3500	15750000	750000	17400	15500	4000	36.00	20.70	16997200	640800	16356400	365211000
17	3500	15750000	750000	17400	15500	4000	36.00	20.70	16604000	640800	15963200	381174200
18	3500	15750000	750000	17400	15500	4000	36.00	20.70	16210700	640800	15569900	396744100
19	3500	15750000	750000	17400	15500	4000	36.00	20.70	15817400	640800	15176600	411920700
20	3500	15750000	750000	17400	15500	4000	36.00	20.70	15424200	640800	14783400	426704100
21	1500	6750000	321400	7500	6600	1700	36.00	20.70	11745100	272800	11472300	438176400
22	1500	6750000	321400	7500	6600	1700	36.00	20.70	11351900	272800	11079100	449255500
23	1500	6750000	321400	7500	6600	1700	36.00	20.70	10958600	272800	10685800	459941300
24	1500	6750000	321400	7500	6600	1700	36.00	20.70	10565300	272800	10292500	470233800
25	1500	6750000	321400	7500	6600	1700	36.00	20.70	10172100	272800	9899300	480133100
26	1500	6750000	321400	7500	6600	1700	36.00	20.70	9778800	272800	9506000	489639100
27	1500	6750000	321400	7500	6600	1700	36.00	20.70	9385600	272800	9112800	498751900
28	1500	6750000	321400	7500	6600	1700	36.00	20.70	8992300	272800	8719500	507471400
29	1500	6750000	321400	7500	6600	1700	36.00	20.70	8599000	272800	8326200	515797600
30	1500	6750000	321400	7500	6600	1700	36.00	20.70	8205800	272800	7933000	523730600
TOT	127500	573750000	27321000	634000	564000	145500			546628100	22897500	523730600	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	20.01	0.84	19.17
MILLS PER KILOWATT-HOUR	8.57	0.35	8.22
CENTS PER MILLION BTU HEAT INPUT	95.27	3.99	91.28
DOLLARS PER TON OF SULFUR REMOVED	862.19	36.12	826.07
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	196363000	8956000	187407000

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	18.44	0.84	17.60
MILLS PER KILOWATT-HOUR	7.90	0.36	7.54
CENTS PER MILLION BTU HEAT INPUT	87.80	4.00	83.80
DOLLARS PER TON OF SULFUR REMOVED	794.99	36.26	758.73

TABLE A-115. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 5.0% sulfur)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	561,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	9.9
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	9.9
Stack gas reheat (four indirect steam reheaters)	1,136,000	2.6
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	11.2
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	3,465,000	7.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	11,011,000	25.0
Sulfur production (complete unit for sulfur production)	10,311,000	23.4
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	835,000	1.9
Subtotal	40,941,000	93.1
Services, utilities, and miscellaneous	2,456,000	5.6
Total excluding pond	43,397,000	98.7
Pond	590,000	1.3
Total direct investment	43,987,000	100.0
Indirect Investment		
Engineering design and supervision	2,595,000	5.9
Architect and engineering contractor	641,000	1.4
Construction expense	5,799,000	13.2
Contractor fees	1,703,000	3.9
Total indirect investment	10,738,000	24.4
Contingency	10,945,000	24.9
Total fixed investment	65,670,000	149.3
Other Capital Charges		
Allowance for startup and modifications	6,508,000	14.8
Interest during construction	7,880,000	17.9
Total depreciable investment	80,058,000	182.0
Land	42,000	0.1
Working capital	2,223,000	5.1
Total capital investment	82,323,000	187.2

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-116. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 5.0% sulfur)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	9,690 tons	103.00/ton	998,100	3.95
Catalyst			6,200	0.02
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.19
Filter aid	108 tons	189.00/ton	20,400	0.08
Coal	44,820 tons	25.00/ton	1,120,500	4.44
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			2,195,200	8.69
Conversion costs				
Operating labor and supervision	51,020 man-hr	12.50/man-hr	637,800	2.52
Utilities				
Fuel oil	656,900 gal	0.40/gal	262,800	1.04
Steam	2,193,100 MBtu	2.00/MBtu	4,386,200	17.36
Process water	6,456,400 kgal	0.12/kgal	774,800	3.07
Electricity	94,187,200 kWh	0.029/kWh	2,731,400	10.81
Heat credit	90,300 MBtu	2.00/MBtu	(180,600)	(0.71)
Maintenance				
Labor and material			2,621,500	10.37
Analyses	9,130 man-hr	17.00/man-hr	155,200	0.61
Total conversion costs			11,389,100	45.07
Total direct costs			13,584,300	53.76
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,803,500	19.01
Average cost of capital and taxes at 8.6% of total capital investment			7,079,800	28.02
Overheads				
Plant, 50% of conversion costs less utilities			1,707,200	6.76
Administrative, 10% of operating labor			63,800	0.25
Marketing, 10% of byproduct sales revenue			219,100	0.87
Total indirect costs			13,873,400	54.91
Gross average annual revenue requirements			27,457,700	108.67
Byproduct Sales Revenue				
Sulfur	47,700 tons	40.00/ton	(1,908,000)	(7.55)
Sodium sulfate	12,300 tons	23.00/ton	(282,900)	(1.12)
Net average annual revenue requirements			25,266,800	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	7.22	16.84	0.80	472

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 53,500 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $43,987,000; total depreciable investment, $80,058,000; and total capital investment, $82,323,000.
- All tons shown are 2,000 lb.

TABLE A-117

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 5.0% S, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 52323000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	53500	47700	12300	36.00	20.70	34318700	1971800	32346900	32346900
2	7000	31500000	1500000	53500	47700	12300	36.00	20.70	33859700	1971800	31887900	64234800
3	7000	31500000	1500000	53500	47700	12300	36.00	20.70	33400700	1971800	31428900	95663700
4	7000	31500000	1500000	53500	47700	12300	36.00	20.70	32941700	1971800	30969900	126633600
5	7000	31500000	1500000	53500	47700	12300	36.00	20.70	32482700	1971800	30510900	157144500
6	7000	31500000	1500000	53500	47700	12300	36.00	20.70	32023700	1971800	30051900	187196400
7	7000	31500000	1500000	53500	47700	12300	36.00	20.70	31564700	1971800	29592900	216789300
8	7000	31500000	1500000	53500	47700	12300	36.00	20.70	31105700	1971800	29133900	245923200
9	7000	31500000	1500000	53500	47700	12300	36.00	20.70	30646700	1971800	28674900	274598100
10	7000	31500000	1500000	53500	47700	12300	22.50	20.70	30187700	1327900	28859800	303457900
11	5000	22500000	1071400	38200	34100	8800	36.00	20.70	25879600	1409800	24469800	327927700
12	5000	22500000	1071400	38200	34100	8800	36.00	20.70	25420600	1409800	24010800	351938500
13	5000	22500000	1071400	38200	34100	8800	36.00	20.70	24961600	1409800	23551800	375490300
14	5000	22500000	1071400	38200	34100	8800	36.00	20.70	24502600	1409800	23092800	398583100
15	5000	22500000	1071400	38200	34100	8800	36.00	20.70	24043600	1409800	22633800	421216900
16	3500	15750000	750000	26800	23800	6100	36.00	20.70	20595600	983100	19612500	440829400
17	3500	15750000	750000	26800	23800	6100	36.00	20.70	20136600	983100	19153500	459982900
18	3500	15750000	750000	26800	23800	6100	36.00	20.70	19677600	983100	18694500	478677400
19	3500	15750000	750000	26800	23800	6100	36.00	20.70	19218600	983100	18235500	496912900
20	3500	15750000	750000	26800	23800	6100	36.00	20.70	18759600	983100	17776500	514689400
21	1500	6750000	321400	11500	10200	2600	36.00	20.70	14045200	421000	13624200	528313600
22	1500	6750000	321400	11500	10200	2600	36.00	20.70	13586200	421000	13165200	541478800
23	1500	6750000	321400	11500	10200	2600	36.00	20.70	13127200	421000	12706200	554185000
24	1500	6750000	321400	11500	10200	2600	36.00	20.70	12668200	421000	12247200	566432200
25	1500	6750000	321400	11500	10200	2600	36.00	20.70	12209200	421000	11788200	578220400
26	1500	6750000	321400	11500	10200	2600	36.00	20.70	11750200	421000	11329200	589549600
27	1500	6750000	321400	11500	10200	2600	36.00	20.70	11291200	421000	10870200	600419800
28	1500	6750000	321400	11500	10200	2600	36.00	20.70	10832200	421000	10411200	610831000
29	1500	6750000	321400	11500	10200	2600	36.00	20.70	10373200	421000	9952200	620783200
30	1500	6750000	321400	11500	10200	2600	36.00	20.70	9914200	421000	9493200	630276400
TOT	127500	573750000	27321000	975000	868500	223500			665525000	35248600	630276400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	24.36	1.29	23.07
MILLS PER KILOWATT-HOUR	10.44	0.55	9.89
CENTS PER MILLION BTU HEAT INPUT	116.00	6.15	109.85
DOLLARS PER TON OF SULFUR REMOVED	682.59	36.15	646.44

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 239853200 13783100 226070100

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	22.52	1.29	21.23
MILLS PER KILOWATT-HOUR	9.65	0.55	9.10
CENTS PER MILLION BTU HEAT INPUT	107.25	6.16	101.09
DOLLARS PER TON OF SULFUR REMOVED	631.36	36.28	595.08

TABLE A-118. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	634,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	7,010,000	11.8
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	7,525,000	12.7
Stack gas reheat (four indirect steam reheaters)	1,846,000	3.0
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	8,232,000	13.9
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	4,088,000	6.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	13,234,000	22.3
Sulfur production (complete unit for sulfur production)	11,914,000	20.1
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	982,000	1.7
Subtotal	55,465,000	93.5
Services, utilities, and miscellaneous	3,328,000	5.6
Total excluding pond	58,793,000	99.1
Pond	543,000	0.9
Total direct investment	59,336,000	100.0
Indirect Investment		
Engineering design and supervision	2,934,000	4.9
Architect and engineering contractor	726,000	1.2
Construction expense	7,432,000	12.6
Contractor fees	2,138,000	3.6
Total indirect investment	13,230,000	22.3
Contingency	14,513,000	24.5
Total fixed investment	87,079,000	146.8
Other Capital Charges		
Allowance for startup and modifications	8,654,000	14.6
Interest during construction	10,449,000	17.6
Total depreciable investment	106,182,000	179.0
Land	66,000	0.1
Working capital	2,999,000	5.0
Total capital investment	109,247,000	184.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-119. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	12,600 tons	103.00/ton	1,297,800	3.77
Catalyst			8,000	0.02
Agricultural limestone	6,480 tons	15.00/ton	97,200	0.28
Filter aid	140 tons	189.00/ton	26,500	0.08
Coal	58,280 tons	25.00/ton	1,457,000	4.24
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			2,887,900	8.40
Conversion costs				
Operating labor and supervision	67,180 man-hr	12.50/man-hr	839,800	2.44
Utilities				
Fuel oil	854,200 gal	0.40/gal	341,700	0.99
Steam	3,141,800 MBtu	2.00/MBtu	6,283,600	18.27
Process water	8,528,400 kgal	0.12/kgal	1,023,400	2.98
Electricity	154,536,700 kWh	0.028/kWh	4,327,000	12.58
Heat credit	117,400 MBtu	2.00/MBtu	(234,800)	(0.68)
Maintenance				
Labor and material			2,955,900	8.60
Analyses	13,810 man-hr	17.00/man-hr	234,800	0.68
Total conversion costs			15,771,400	45.86
Total direct costs			18,659,300	54.26
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			6,795,600	19.76
Average cost of capital and taxes at 8.6% of total capital investment			9,395,200	27.32
Overheads				
Plant, 50% of conversion costs less utilities			2,015,200	5.86
Administrative, 10% of operating labor			84,000	0.25
Marketing, 10% of byproduct sales revenue			284,800	0.83
Total indirect costs			18,574,800	54.02
Gross average annual revenue requirements			37,234,100	108.28
Byproduct Sales Revenue				
Sulfur	62,000 tons	40.00/ton	(2,480,000)	(7.21)
Sodium sulfate	16,000 tons	23.00/ton	(368,000)	(1.07)
Net average annual revenue requirements			34,386,100	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.91	11.46	0.55	494

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 25 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,999,900 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 69,560 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $59,336,000; total depreciable investment, $106,182,000; and total capital investment, $109,247,000.
- All tons shown are 2,000 lb.

TABLE A-120

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 1000 MW EXISTING, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 109247000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	63000000	3000000	69600	62000	16000	36.00	20.70	47053000	2563200	44489800	44489800
7	7000	63000000	3000000	69600	62000	16000	36.00	20.70	46322400	2563200	43759200	88249000
8	7000	63000000	3000000	69600	62000	16000	36.00	20.70	45591900	2563200	43028700	131277700
9	7000	63000000	3000000	69600	62000	16000	36.00	20.70	44861400	2563200	42298200	173575900
10	7000	63000000	3000000	69600	62000	16000	22.50	20.70	44130800	1726200	42404600	215980500
11	5000	45000000	2142900	49700	44300	11400	36.00	20.70	38101300	1830800	36270500	252251000
12	5000	45000000	2142900	49700	44300	11400	36.00	20.70	37370800	1830800	35540000	287791000
13	5000	45000000	2142900	49700	44300	11400	36.00	20.70	36640200	1830800	34809400	322600400
14	5000	45000000	2142900	49700	44300	11400	36.00	20.70	35909700	1830800	34078900	356679300
15	5000	45000000	2142900	49700	44300	11400	36.00	20.70	35179200	1830800	33348400	390027700
16	3500	31500000	1500000	34800	31000	8000	36.00	20.70	30354800	1281600	29073200	419100900
17	3500	31500000	1500000	34800	31000	8000	36.00	20.70	29624300	1281600	28342700	447443600
18	3500	31500000	1500000	34800	31000	8000	36.00	20.70	28893800	1281600	27612200	475055800
19	3500	31500000	1500000	34800	31000	8000	36.00	20.70	28163200	1281600	26881600	501937400
20	3500	31500000	1500000	34800	31000	8000	36.00	20.70	27432700	1281600	26151100	528088300
21	1500	13500000	642900	14900	13300	3400	36.00	20.70	20928000	549200	20378800	548467300
22	1500	13500000	642900	14900	13300	3400	36.00	20.70	20197400	549200	19648200	568115500
23	1500	13500000	642900	14900	13300	3400	36.00	20.70	19466900	549200	18917700	587033200
24	1500	13500000	642900	14900	13300	3400	36.00	20.70	18736300	549200	18187100	605220300
25	1500	13500000	642900	14900	13300	3400	36.00	20.70	18005800	549200	17456600	622676900
26	1500	13500000	642900	14900	13300	3400	36.00	20.70	17275300	549200	16726100	639403000
27	1500	13500000	642900	14900	13300	3400	36.00	20.70	16544700	549200	15995500	655398500
28	1500	13500000	642900	14900	13300	3400	36.00	20.70	15814200	549200	15265000	670663500
29	1500	13500000	642900	14900	13300	3400	36.00	20.70	15083700	549200	14534500	685198000
30	1500	13500000	642900	14900	13300	3400	36.00	20.70	14353100	549200	13803900	699001900
TOT	92500	632500000	39643500	919500	819500	211000			732034900	33033000	699001900	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	18.47	0.84	17.63
MILLS PER KILOWATT-HOUR	7.91	0.35	7.56
CENTS PER MILLION BTU HEAT INPUT	87.93	3.97	83.96
DOLLARS PER TON OF SULFUR REMOVED	796.12	35.92	760.20
PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS	299515300	14864100	284651200

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	16.67	0.82	15.85
MILLS PER KILOWATT-HOUR	7.15	0.36	6.79
CENTS PER MILLION BTU HEAT INPUT	79.40	3.94	75.46
DOLLARS PER TON OF SULFUR REMOVED	718.78	35.67	683.11

TABLE A-121. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 1,000 MW new)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	624,000	1.1
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	6,853,000	11.8
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	7,324,000	12.6
Stack gas reheat (four indirect steam reheaters)	1,802,000	3.1
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	8,026,000	13.8
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	4,001,000	6.9
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	12,916,000	22.2
Sulfur production (complete unit for sulfur production)	11,694,000	20.0
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	962,000	1.7
Subtotal	54,202,000	93.2
Services, utilities, and miscellaneous	3,252,000	5.6
Total excluding pond	57,454,000	98.8
Pond	680,000	1.2
Total direct investment	58,134,000	100.0
Indirect Investment		
Engineering design and supervision	2,927,000	5.0
Architect and engineering contractor	723,000	1.2
Construction expense	7,308,000	12.7
Contractor fees	2,105,000	3.6
Total indirect investment	13,063,000	22.5
Contingency	14,239,000	24.5
Total fixed investment	85,436,000	147.0
Other Capital Charges		
Allowance for startup and modifications	8,476,000	14.6
Interest during construction	10,252,000	17.6
Total depreciable investment	104,164,000	179.2
Land	69,000	0.1
Working capital	2,915,000	5.0
Total capital investment	107,148,000	184.3

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-122. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 1,000 MW new)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	12,200 tons	103.00/ton	1,256,600	3.79
Catalyst			7,700	0.02
Agricultural limestone	6,260 tons	15.00/ton	93,900	0.28
Filter aid	135 tons	189.00/ton	25,500	0.08
Coal	56,340 tons	25.00/ton	1,408,500	4.25
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			2,793,600	8.43
Conversion costs				
Operating labor and supervision	67,180 man-hr	12.50/man-hr	839,800	2.53
Utilities				
Fuel oil	825,700 gal	0.40/gal	330,300	1.00
Steam	3,037,000 MBtu	2.00/MBtu	6,074,000	18.31
Process water	8,244,000 kgal	0.12/kgal	989,300	2.98
Electricity	149,402,900 kWh	0.028/kWh	4,183,300	12.61
Heat credit	113,500 MBtu	2.00/MBtu	(227,000)	(0.68)
Maintenance				
Labor and material			2,893,100	8.71
Analyses	13,810 man-hr	17.00/man-hr	234,800	0.71
Total conversion costs			15,317,600	46.18
Total direct costs			18,111,200	54.61
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			6,249,800	18.85
Average cost of capital and taxes at 8.6% of total capital investment			9,214,700	27.78
Overheads				
Plant, 50% of conversion costs less utilities			1,983,800	5.98
Administrative, 10% of operating labor			84,000	0.25
Marketing, 10% of byproduct sales revenue			275,200	0.83
Total indirect costs			17,807,500	53.69
Gross average annual revenue requirements			35,918,700	108.30
Byproduct Sales Revenue				
Sulfur	59,900 tons	40.00/ton	(2,396,000)	(7.22)
Sodium sulfate	15,470 tons	23.00/ton	(355,800)	(1.08)
Net average annual revenue requirements			33,166,900	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	4.74	11.44	0.54	493

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 2,900,100 tons/yr, 8,700 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 67,240 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $58,134,000; total depreciable investment, $104,164,000; and total capital investment, $107,148,000.
- All tons shown are 2,000 lb.

TABLE A-123

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: 1000MW, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 107148000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	60900000	2900000	67200	59900	15500	36.00	20.70	44858800	2477300	42381500	42381500
2	7000	60900000	2900000	67200	59900	15500	36.00	20.70	44261600	2477300	41784300	84165800
3	7000	60900000	2900000	67200	59900	15500	36.00	20.70	43664400	2477300	41187100	125352900
4	7000	60900000	2900000	67200	59900	15500	36.00	20.70	43067200	2477300	40589900	165942800
5	7000	60900000	2900000	67200	59900	15500	36.00	20.70	42470000	2477300	39992700	205935500
6	7000	60900000	2900000	67200	59900	15500	36.00	20.70	41872800	2477300	39395500	245331000
7	7000	60900000	2900000	67200	59900	15500	36.00	20.70	41275500	2477300	38798200	284129200
8	7000	60900000	2900000	67200	59900	15500	36.00	20.70	40678300	2477300	38201000	322330200
9	7000	60900000	2900000	67200	59900	15500	36.00	20.70	40081100	2477300	37603800	359934000
10	7000	60900000	2900000	67200	59900	15500	22.50	20.70	39483900	1668700	37815200	397749200
11	5000	43500000	2071400	48000	42800	11100	36.00	20.70	33743600	1770600	31973000	429722200
12	5000	43500000	2071400	48000	42800	11100	36.00	20.70	33146400	1770600	31375800	461098000
13	5000	43500000	2071400	48000	42800	11100	36.00	20.70	32549200	1770600	30778600	491876600
14	5000	43500000	2071400	48000	42800	11100	36.00	20.70	31952000	1770600	30181400	522058000
15	5000	43500000	2071400	48000	42800	11100	36.00	20.70	31354800	1770600	29584200	551642200
16	3500	30450000	1450000	33600	29900	7700	36.00	20.70	26782700	1235800	25546900	577189100
17	3500	30450000	1450000	33600	29900	7700	36.00	20.70	26185500	1235800	24949700	602138800
18	3500	30450000	1450000	33600	29900	7700	36.00	20.70	25588300	1235800	24352500	626491300
19	3500	30450000	1450000	33600	29900	7700	36.00	20.70	24991100	1235800	23755300	650246600
20	3500	30450000	1450000	33600	29900	7700	36.00	20.70	24393900	1235800	23158100	673404700
21	1500	13050000	621400	14400	12800	3300	36.00	20.70	18185900	529100	17656800	691061500
22	1500	13050000	621400	14400	12800	3300	36.00	20.70	17588700	529100	17059600	708121100
23	1500	13050000	621400	14400	12800	3300	36.00	20.70	16991500	529100	16462400	724583500
24	1500	13050000	621400	14400	12800	3300	36.00	20.70	16394300	529100	15865200	740448700
25	1500	13050000	621400	14400	12800	3300	36.00	20.70	15797100	529100	15268000	755716700
26	1500	13050000	621400	14400	12800	3300	36.00	20.70	15199900	529100	14670800	770387500
27	1500	13050000	621400	14400	12800	3300	36.00	20.70	14602700	529100	14073600	784461100
28	1500	13050000	621400	14400	12800	3300	36.00	20.70	14005500	529100	13476400	797937500
29	1500	13050000	621400	14400	12800	3300	36.00	20.70	13408300	529100	12879200	810816700
30	1500	13050000	621400	14400	12800	3300	36.00	20.70	12811100	529100	12282000	823098700
TOT	127500	1109250000	52821000	1224000	1090500	282000			867386100	44287400	823098700	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	16.42	0.84	15.58
MILLS PER KILOWATT-HOUR	6.80	0.34	6.46
CENTS PER MILLION BTU HEAT INPUT	78.20	4.00	74.20
DOLLARS PER TON OF SULFUR REMOVED	708.65	36.18	672.47

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 313281000 17316600 295964400

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	15.22	0.85	14.37
MILLS PER KILOWATT-HOUR	6.30	0.34	5.96
CENTS PER MILLION BTU HEAT INPUT	72.46	4.01	68.45
DOLLARS PER TON OF SULFUR REMOVED	656.64	36.30	620.34

TABLE A-124. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: 90% SO_2 removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	487,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	11.2
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	11.1
Stack gas reheat (four indirect steam reheaters)	1,136,000	2.9
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	12.5
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,868,000	7.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,926,000	22.8
Sulfur production (complete unit for sulfur production)	8,740,000	22.3
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	693,000	1.8
Subtotal	36,472,000	93.2
Services, utilities, and miscellaneous	2,188,000	5.6
Total excluding pond	38,660,000	98.8
Pond	480,000	1.2
Total direct investment	39,140,000	100.0
Indirect Investment		
Engineering design and supervision	2,478,000	6.3
Architect and engineering contractor	613,000	1.6
Construction expense	5,263,000	13.4
Contractor fees	1,558,000	4.0
Total indirect investment	9,912,000	25.3
Contingency	9,810,000	25.1
Total fixed investment	58,862,000	150.4
Other Capital Charges		
Allowance for startup and modifications	5,838,000	14.9
Interest during construction	7,063,000	18.0
Total depreciable investment	71,763,000	183.3
Land	42,000	0.1
Working capital	1,838,000	4.7
Total capital investment	73,643,000	188.1

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-125. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: 90% SO_2 removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	7,180 tons	103.00/ton	739,500	3.36
Catalyst			4,600	0.02
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.22
Filter aid	80 tons	189.00/ton	15,100	0.07
Coal	33,200 tons	25.00/ton	830,000	3.78
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			1,639,200	7.46
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.70
Utilities				
Fuel oil	486,600 gal	0.40/gal	194,600	0.89
Steam	1,731,900 MBtu	2.00/MBru	3,463,800	15.77
Process water	4,831,300 kgal	0.12/kgal	579,800	2.64
Electricity	81,867,400 kWh	0.029/kWh	2,374,200	10.81
Heat credit	66,900 MBtu	2.00/MBtu	(133,800)	(0.61)
Maintenance				
Labor and material			2,334,000	10.62
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.66
Total conversion costs			9,550,900	43.48
Total direct costs			11,190,100	50.94
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,305,800	19.60
Average cost of capital and taxes at 8.6% of total capital investment			6,333,300	28.83
Overheads				
Plant, 50% of conversion costs less utilities			1,536,200	7.00
Administrative, 10% of operating labor			59,400	0.27
Marketing, 10% of byproduct sales revenue			162,100	0.74
Total indirect costs			12,396,800	56.44
Gross average annual revenue requirements			23,586,900	107.38
Byproduct Sales Revenue				
Sulfur	35,300 tons	40.00/ton	(1,412,000)	(6.43)
Sodium sulfate	9,110 tons	23.00/ton	(209,500)	(1.95)
Net average annual revenue requirements			21,965,400	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.28	14.64	0.70	554

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 39,620 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $39,140,000; total depreciable investment, $71,763,000; and total capital investment, $73,643,000.
- All tons shown are 2,000 lb.

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TABLE A-126

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROMBASE CASE: 90% S REMOVAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 73643000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	39600	35300	9100	36.00	20.70	29758300	1459200	28299100	28299100
2	7000	31500000	1500000	39600	35300	9100	36.00	20.70	29346900	1459200	27887700	56186800
3	7000	31500000	1500000	39600	35300	9100	36.00	20.70	28935400	1459200	27476200	83663000
4	7000	31500000	1500000	39600	35300	9100	36.00	20.70	28524000	1459200	27064800	110727800
5	7000	31500000	1500000	39600	35300	9100	36.00	20.70	28112500	1459200	26653300	137381100
6	7000	31500000	1500000	39600	35300	9100	36.00	20.70	27701100	1459200	26241900	163623000
7	7000	31500000	1500000	39600	35300	9100	36.00	20.70	27289600	1459200	25830400	189453400
8	7000	31500000	1500000	39600	35300	9100	36.00	20.70	26878200	1459200	25419000	214872400
9	7000	31500000	1500000	39600	35300	9100	36.00	20.70	26466800	1459200	25007600	239880000
10	7000	31500000	1500000	39600	35300	9100	22.50	20.70	26055300	982700	25072600	264952600
11	5000	22500000	1071400	28300	25200	6500	36.00	20.70	22475200	1041800	21433400	286386000
12	5000	22500000	1071400	28300	25200	6500	36.00	20.70	22063700	1041800	21021900	307407900
13	5000	22500000	1071400	28300	25200	6500	36.00	20.70	21652300	1041800	20610500	328018400
14	5000	22500000	1071400	28300	25200	6500	36.00	20.70	21240900	1041800	20199100	348217500
15	5000	22500000	1071400	28300	25200	6500	36.00	20.70	20829400	1041800	19787600	368005100
16	3500	15750000	750000	19800	17700	4600	36.00	20.70	17950000	732400	17217600	385222700
17	3500	15750000	750000	19800	17700	4600	36.00	20.70	17538500	732400	16806100	402028800
18	3500	15750000	750000	19800	17700	4600	36.00	20.70	17127100	732400	16394700	418423500
19	3500	15750000	750000	19800	17700	4600	36.00	20.70	16715700	732400	15983300	434406800
20	3500	15750000	750000	19800	17700	4600	36.00	20.70	16304200	732400	15571800	449978600
21	1500	6750000	321400	8500	7600	2000	36.00	20.70	12358900	315000	12043900	462022500
22	1500	6750000	321400	8500	7600	2000	36.00	20.70	11947400	315000	11632400	473654900
23	1500	6750000	321400	8500	7600	2000	36.00	20.70	11536000	315000	11221000	484875900
24	1500	6750000	321400	8500	7600	2000	36.00	20.70	11124500	315000	10809500	495685400
25	1500	6750000	321400	8500	7600	2000	36.00	20.70	10713100	315000	10398100	506083500
26	1500	6750000	321400	8500	7600	2000	36.00	20.70	10301700	315000	9986700	516070200
27	1500	6750000	321400	8500	7600	2000	36.00	20.70	9890200	315000	9575200	525645400
28	1500	6750000	321400	8500	7600	2000	36.00	20.70	9478800	315000	9163800	534809200
29	1500	6750000	321400	8500	7600	2000	36.00	20.70	9067300	315000	8752300	543561500
30	1500	6750000	321400	8500	7600	2000	36.00	20.70	8655900	315000	8340900	551902400
TOT	127500	573750000	27321000	721500	643500	166500			578038900	26136500	551902400	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	21.16	0.96	20.20
MILLS PER KILOWATT-HOUR	9.07	0.41	8.66
CENTS PER MILLION BTU HEAT INPUT	100.75	4.56	96.19
DOLLARS PER TON OF SULFUR REMOVED	801.16	36.22	764.94

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 207846100 10203800 197642300

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	19.52	0.96	18.56
MILLS PER KILOWATT-HOUR	8.36	0.41	7.95
CENTS PER MILLION BTU HEAT INPUT	92.94	4.57	88.37
DOLLARS PER TON OF SULFUR REMOVED	739.14	36.29	702.85

TABLE A-127. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: oil-fired, existing)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	311,000	1.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	3,908,000	17.4
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,213,000	18.7
Stack gas reheat (four direct oil-fired reheaters)	1,063,000	4.7
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	1,577,000	7.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	4,593,000	20.4
Sulfur production (complete unit for sulfur production)	5,184,000	23.0
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	385,000	1.7
Subtotal	21,234,000	94.3
Services, utilities, and miscellaneous	1,274,000	5.7
Total direct investment	22,508,000	100.0
Indirect Investment		
Engineering design and supervision	2,010,000	8.9
Architect and engineering contractor	502,000	2.2
Construction expense	3,314,000	14.7
Contractor fees	1,023,000	4.6
Total indirect investment	6,849,000	30.4
Contingency	5,871,000	26.1
Total fixed investment	35,228,000	156.5
Other Capital Charges		
Allowance for startup and modifications	3,523,000	15.6
Interest during construction	4,227,000	18.8
Total depreciable investment	42,978,000	190.9
Land	27,000	0.1
Working capital	1,069,000	5.0
Total capital investment	44,074,000	196.0

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.
Stack gas reheat to 175°F by indirect steam reheat.
Minimum in-process storage; only pumps are spared.
Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.
Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-128. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: oil-fired, existing)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	2,780 tons	103.00/ton	286,300	2.11
Catalyst			1,800	0.01
Agricultural limestone	2,740 tons	15.00/ton	41,100	0.30
Filter aid	31 tons	189.00/ton	5,900	0.04
Coal	12,840 tons	25.00/ton	321,000	2.37
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			657,500	4.84
Conversion costs				
Operating labor and supervision	45,440 man-hr	12.50/man-hr	568,000	4.19
Utilities				
Fuel oil	2,626,800 gal	0.40/gal	1,050,700	7.74
Steam	509,700 MBtu	2.00/MBtu	1,019,400	7.51
Process water	1,956,900 kgal	0.12/kgal	234,800	1.73
Electricity	53,247,000 kWh	0.029/kWh	1,544,200	11.38
Heat credit	25,900 MBtu	2.00/MBtu	(51,800)	(0.38)
Maintenance				
Labor and material			1,350,500	9.95
Analyses	8,130 man-hr	17.00/man-hr	138,200	1.02
Total conversion costs			5,854,000	43.14
Total direct costs			6,511,500	47.98
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.4% of total depreciable investment			2,750,600	20.27
Average cost of capital and taxes at 8.6% of total capital investment			3,790,400	27.93
Overheads				
Plant, 50% of conversion costs less utilities			1,028,400	7.58
Administrative, 10% of operating labor			56,800	0.42
Marketing, 10% of byproduct sales revenue			62,900	0.46
Total indirect costs			7,689,100	56.66
Gross average annual revenue requirements			14,200,600	104.64
Byproduct Sales Revenue				
Sulfur	13,700 tons	40.00/ton	(548,000)	(4.04)
Sodium sulfate	3,530 tons	23.00/ton	(81,200)	(0.60)
Net average annual revenue requirements			13,571,400	100.00

	Mills/kWh	$/bbl oil burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	3.88	2.54	0.42	885

Basis

Midwest plant location, 1980 revenue requirements.
Remaining life of power plant, 25 yr.
Power unit on-stream time, 7,000 hr/yr.
Oil burned, 5,350,000 bbl/yr, 9,200 Btu/kWh.
Stack gas reheat to 175°F.
Sulfur removed, 15,330 short tons/yr.
Investment and revenue requirement for removal and disposal of fly ash excluded.
Total direct investment, $22,508,000; total depreciable investment, $42,978,000; and total capital investment, $44,074,000.
All tons shown are 2,000 lb.

TABLE A-129

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: OIL FIRED EXISTING REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 44074000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, BARRELS OIL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1												
2												
3												
4												
5												
6	7000	32200000	5324100	15300	13700	3500	36.00	20.70	18214600	565700	17648900	17648900
7	7000	32200000	5324100	15300	13700	3500	36.00	20.70	17918900	565700	17353200	35002100
8	7000	32200000	5324100	15300	13700	3500	36.00	20.70	17623300	565700	17057600	52059700
9	7000	32200000	5324100	15300	13700	3500	36.00	20.70	17327600	565700	16761900	68821600
10	7000	32200000	5324100	15300	13700	3500	36.00	20.70	17031900	380800	16651100	85472700
11	5000	23000000	3802900	11000	9800	2500	36.00	20.70	14893000	404600	14488400	99961100
12	5000	23000000	3802900	11000	9800	2500	36.00	20.70	14597300	404600	14192700	114153800
13	5000	23000000	3802900	11000	9800	2500	36.00	20.70	14301600	404600	13897000	128050800
14	5000	23000000	3802900	11000	9800	2500	36.00	20.70	14005900	404600	13601300	141652100
15	5000	23000000	3802900	11000	9800	2500	36.00	20.70	13710300	404600	13305700	154957800
16	3500	16100000	2662000	7700	6800	1800	36.00	20.70	11971400	282100	11689300	166647100
17	3500	16100000	2662000	7700	6800	1800	36.00	20.70	11675700	282100	11393600	178040700
18	3500	16100000	2662000	7700	6800	1800	36.00	20.70	11380000	282100	11097900	189138600
19	3500	16100000	2662000	7700	6800	1800	36.00	20.70	11084300	282100	10802200	199940800
20	3500	16100000	2662000	7700	6800	1800	36.00	20.70	10788600	282100	10506500	210447300
21	1500	6900000	1140900	3300	2900	800	36.00	20.70	8406300	121000	8285300	218732600
22	1500	6900000	1140900	3300	2900	800	36.00	20.70	8110600	121000	7989600	226722200
23	1500	6900000	1140900	3300	2900	800	36.00	20.70	7814900	121000	7693900	234416100
24	1500	6900000	1140900	3300	2900	800	36.00	20.70	7519200	121000	7398200	241814300
25	1500	6900000	1140900	3300	2900	800	36.00	20.70	7223500	121000	7102500	248916800
26	1500	6900000	1140900	3300	2900	800	36.00	20.70	6927800	121000	6806800	255723600
27	1500	6900000	1140900	3300	2900	800	36.00	20.70	6632100	121000	6511100	262234700
28	1500	6900000	1140900	3300	2900	800	36.00	20.70	6336500	121000	6215500	268450200
29	1500	6900000	1140900	3300	2900	800	36.00	20.70	6040800	121000	5919800	274370000
30	1500	6900000	1140900	3300	2900	800	36.00	20.70	5743100	121000	5626100	279996100
TOT	92500	425500000	70354000	203000	180500	47000			287281200	7287100	279994100	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER BARREL OF OIL BURNED	4.08	0.10	3.98
MILLS PER KILOWATT-HOUR	6.21	0.16	6.05
CENTS PER MILLION BTU HEAT INPUT	67.52	1.72	65.80
DOLLARS PER TON OF SULFUR REMOVED	1415.18	35.90	1379.28

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 116641600 3280400 113361200

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER BARREL OF OIL BURNED	3.66	0.10	3.56
MILLS PER KILOWATT-HOUR	5.57	0.16	5.41
CENTS PER MILLION BTU HEAT INPUT	60.50	1.70	58.80
DOLLARS PER TON OF SULFUR REMOVED	1270.61	35.74	1234.87

TABLE A-130. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: alternate conversion in sulfur production unit)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.3
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,376,000	11.3
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	11.2
Stack gas reheat (four indirect steam reheaters)	1,136,000	2.9
Chloride purge (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	4,894,000	12.6
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	7.3
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,805,000	22.6
Sulfur production (complete unit for sulfur production)	8,653,000	22.3
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	639,000	1.7
Subtotal	35,954,000	93.2
Services, utilities, and miscellaneous	2,157,000	5.6
Total excluding pond	38,111,000	98.8
Pond	475,000	1.2
Total direct investment	38,586,000	100.0
Indirect Investment		
Engineering design and supervision	2,469,000	6.3
Architect and engineering contractor	611,000	1.6
Construction expense	5,201,000	13.5
Contractor fees	1,542,000	4.0
Total indirect investment	9,823,000	25.4
Contingency	9,682,000	25.1
Total fixed investment	58,091,000	150.5
Other Capital Charges		
Allowance for startup and modifications	5,762,000	14.9
Interest during construction	6,971,000	18.1
Total depreciable investment	70,824,000	183.5
Land	42,000	0.1
Working capital	1,789,000	4.7
Total capital investment	72,655,000	188.3

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-131. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: alternate conversion in sulfur production unit)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	2.99
Catalyst			4,000	0.02
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.22
Filter aid	32 tons	189.00/ton	6,000	0.03
Coal	32,580 tons	25.00/ton	814,500	3.75
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			1,523,400	7.02
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.74
Utilities				
Fuel oil	477,500 gal	0.40/gal	191,000	0.88
Steam	1,689,400 MBtu	2.00/MBtu	3,378,800	15.56
Process water	4,712,400 kgal	0.12/kgal	565,500	2.60
Electricity	80,926,900 kWh	0.029/kWh	2,346,900	10.81
Heat credit	65,600 MBtu	2.00/MBtu	(131,200)	(0.60)
Maintenance				
Labor and material			2,300,900	10.60
Analyses	8,500 man-hr	17.00/man-hr	144,500	0.66
Total conversion costs			9,390,200	43.25
Total direct costs			10,913,600	50.27
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			4,249,400	19.58
Average cost of capital and taxes at 8.6% of total capital investment			6,248,300	28.78
Overheads				
Plant, 50% of conversion costs less utilities			1,519,600	7.00
Administrative, 10% of operating labor			59,400	0.27
Marketing, 10% of byproduct sales revenue			142,400	0.66
Total indirect costs			12,219,100	56.29
Gross average annual revenue requirements			23,132,700	106.56
Byproduct Sales Revenue				
Sulfur	31,000 tons	40.00/ton	(1,240,000)	(5.71)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(0.85)
Net average annual revenue requirements			21,708,700	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	6.20	14.47	0.69	624

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $38,586,000; total depreciable investment, $70,824,000; and total capital investment, $72,655,000.
- All tons shown are 2,000 lb.

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TABLE A-132

WELLMAN-LORD SCRUBBING/ALLIED PROCESS VARIATION FROM BASE CASE: LOW CONVERSION, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 72855000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED RCI FOR POWER COMPANY, $/YEAR	TOTAL NET SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	31000	8000	36.00	20.70	29239000	1281600	27957400	27957400
2	7000	31500000	1500000	34800	31000	8000	36.00	20.70	28832900	1281600	27551300	55508700
3	7000	31500000	1500000	34800	31000	8000	36.00	20.70	28426800	1281600	27145200	82653900
4	7000	31500000	1500000	34800	31000	8000	36.00	20.70	28020800	1281600	26739200	109393100
5	7000	31500000	1500000	34800	31000	8000	36.00	20.70	27614700	1281600	26333100	135726200
6	7000	31500000	1500000	34800	31000	8000	36.00	20.70	27208700	1281600	25927100	161653300
7	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26802600	1281600	25521000	187174300
8	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26396600	1281600	25115000	212289300
9	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25990500	1281600	24708900	236998200
10	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25584500	863100	24721300	261719500
11	5000	22500000	1071400	24800	22100	5700	36.00	20.70	22088500	913600	21174900	282894400
12	5000	22500000	1071400	24800	22100	5700	36.00	20.70	21682400	913600	20768800	303663200
13	5000	22500000	1071400	24800	22100	5700	36.00	20.70	21276400	913600	20362800	324026000
14	5000	22500000	1071400	24800	22100	5700	36.00	20.70	20870300	913600	19956700	343982700
15	5000	22500000	1071400	24800	22100	5700	36.00	20.70	20464300	913600	19550700	363533400
16	3500	15750000	750000	17400	15500	4000	36.00	20.70	17649900	640800	17009100	380542500
17	3500	15750000	750000	17400	15500	4000	36.00	20.70	17243800	640800	16603000	397145500
18	3500	15750000	750000	17400	15500	4000	36.00	20.70	16837800	640800	16197000	413342500
19	3500	15750000	750000	17400	15500	4000	36.00	20.70	16431700	640800	15790900	429133400
20	3500	15750000	750000	17400	15500	4000	36.00	20.70	16025700	640800	15384900	444518300
21	1500	6750000	321400	7500	6600	1700	36.00	20.70	12168600	272800	11895800	456414100
22	1500	6750000	321400	7500	6600	1700	36.00	20.70	11762600	272800	11489800	467903900
23	1500	6750000	321400	7500	6600	1700	36.00	20.70	11356500	272800	11083700	478987600
24	1500	6750000	321400	7500	6600	1700	36.00	20.70	10950400	272800	10677600	489665200
25	1500	6750000	321400	7500	6600	1700	36.00	20.70	10544400	272800	10271600	499936800
26	1500	6750000	321400	7500	6600	1700	36.00	20.70	10138300	272800	9865500	509802300
27	1500	6750000	321400	7500	6600	1700	36.00	20.70	9732300	272800	9459500	519261800
28	1500	6750000	321400	7500	6600	1700	36.00	20.70	9326200	272800	9053400	528315200
29	1500	6750000	321400	7500	6600	1700	36.00	20.70	8920100	272800	8647300	536962500
30	1500	6750000	321400	7500	6600	1700	36.00	20.70	8514100	272800	8241300	545203800
TOT	127500	573750000	27321000	634000	564000	145500			568101300	22897500	545203800	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	20.79	0.83	19.96
MILLS PER KILOWATT-HOUR	8.91	0.36	8.55
CENTS PER MILLION BTU HEAT INPUT	99.02	4.00	95.02
DOLLARS PER TON OF SULFUR REMOVED	896.06	36.12	859.94

PROCESS COST DISCOUNTED AT 11.6% TO INITIAL YEAR, DOLLARS 204203900 8956000 195247500

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	19.17	0.84	18.33
MILLS PER KILOWATT-HOUR	8.22	0.36	7.86
CENTS PER MILLION BTU HEAT INPUT	91.31	4.01	87.30
DOLLARS PER TON OF SULFUR REMOVED	826.73	36.25	790.48

TABLE A-133. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

SUMMARY OF ESTIMATED CAPITAL INVESTMENT

(Variation from base case: wet-scrubbing fly ash removal)

	Investment, $	% of total direct investment
Direct Investment		
Materials handling (conveyors, silos, feeders, bins, shaker, tanks, and pumps)	458,000	1.4
Gas handling (common feed plenum and booster fans, gas ducts and dampers from plenum to absorber, exhaust gas ducts and dampers from absorber to reheater and stack, gas ducts from chloride scrubber to absorber)	4,642,000	14.1
SO_2 absorption (four absorbers and entrainment separators, tanks, pumps, filters, agitators, and heat exchangers)	4,352,000	13.2
Stack gas reheat (four indirect steam reheaters)	1,136,000	3.4
Fly ash removal (four chloride scrubbers and entrainment separators, tanks, agitators, and pumps)	5,296,000	16.0
ESP credit	(4,713,000)	(14.3)
Sulfate crystallization (evaporator-crystallizer, heat exchanger, pumps, agitator, tank, dryer, conveyors, centrifuge, bin, silo, and feeder)	2,641,000	8.0
SO_2 regeneration (evaporators, heat exchangers, strippers, tanks, agitators, pumps, blower, and condensers)	8,144,000	24.7
Sulfur production (complete unit for sulfur production)	8,138,000	24.7
Sulfur storage (storage and shipping facilities for 30-day production of sulfur)	639,000	1.9
Subtotal	30,733,000	93.1
Services, utilities, and miscellaneous	1,844,000	5.6
Total excluding pond	32,577,000	98.7
Pond	425,000	1.3
Total direct investment	33,002,000	100.0
Indirect Investment		
Engineering design and supervision	2,432,000	7.4
Architect and engineering contractor	602,000	1.8
Construction expense	4,569,000	13.8
Contractor fees	1,369,000	4.2
Total indirect investment	8,972,000	27.2
Contingency	8,395,000	25.4
Total fixed investment	50,369,000	152.6
Other Capital Charges		
Allowance for startup and modifications	4,994,000	15.1
Interest during construction	6,044,000	18.3
Total depreciable investment	61,407,000	186.1
Land	42,000	0.1
Working capital	1,768,000	5.4
Total capital investment	63,217,000	191.6

Basis

Evaluation represents project beginning mid-1977, ending mid-1980. Average cost basis for scaling, mid-1979.

Stack gas reheat to 175°F by indirect steam reheat.

Minimum in-process storage; only pumps are spared.

Investment requirements for fly ash removal and disposal excluded; FGD process investment estimate begins with common feed plenum downstream of the ESP.

Construction labor shortages with accompanying overtime pay incentive not considered.

TABLE A-134. WELLMAN-LORD/ALLIED CHEMICAL COAL/SO_2 REDUCTION PROCESS

ANNUAL REVENUE REQUIREMENTS

(Variation from base case: wet-scrubbing fly ash removal)

	Annual quantity	Unit cost, $	Total annual cost, $	% of average annual revenue requirements
Direct Costs				
Raw materials				
Sodium carbonate	6,300 tons	103.00/ton	648,900	3.21
Catalyst			4,000	0.02
Agricultural limestone	3,240 tons	15.00/ton	48,600	0.24
Filter aid	70 tons	189.00/ton	13,200	0.07
Coal	29,140 tons	25.00/ton	728,500	3.60
Sand	180 tons	7.50/ton	1,400	0.01
Total raw materials cost			1,444,600	7.15
Conversion costs				
Operating labor and supervision	47,500 man-hr	12.50/man-hr	593,800	2.94
Utilities				
Fuel oil	427,100 gal	0.40/gal	170,800	0.85
Steam	1,570,900 MBtu	2.00/MBtu	3,141,800	15.54
Process water	4,264,200 kgal	0.12/kgal	511,700	2.53
Electricity	114,122,400 kWh	0.029/kWh	3,309,500	16.37
Heat credit	58,700 MBtu	2.00/MBtu	(117,400)	(0.58)
ESP electricity credit	7,114,900 kWh	0.029/kWh	(206,300)	(1.02)
Maintenance				
Labor and material			1,967,400	9.73
Analyses	8,500 man-hr	17.000/man-hr	144,500	0.72
Total conversion costs			9,515,800	47.08
Total direct costs			10,960,400	54.23
Indirect Costs				
Capital charges				
Depreciation, interim replacements, and insurance at 6.0% of total depreciable investment			3,684,400	18.23
Average cost of capital and taxes at 8.6% of total capital investment			5,436,700	26.90
Overheads				
Plant, 50% of conversion costs less utilities			1,352,900	6.69
Administrative, 10% of operating labor			59,400	0.29
Marketing, 10% of byproduct sales revenue			142,400	0.71
Total indirect costs			10,675,800	52.82
Gross average annual revenue requirements			21,636,200	107.05
Byproduct Sales Revenue				
Sulfur	31,000 tons	40.00/ton	(1,240,000)	(6.14)
Sodium sulfate	8,000 tons	23.00/ton	(184,000)	(0.91)
Net average annual revenue requirements			20,212,200	100.00

	Mills/kWh	$/ton coal burned	$/MBtu heat input	$/ton S removed
Equivalent unit revenue requirements (net)	5.77	13.47	0.64	581

Basis
- Midwest plant location, 1980 revenue requirements.
- Remaining life of power plant, 30 yr.
- Power unit on-stream time, 7,000 hr/yr.
- Coal burned, 1,500,100 tons/yr, 9,000 Btu/kWh.
- Stack gas reheat to 175°F.
- Sulfur removed, 34,780 short tons/yr.
- Investment and revenue requirement for removal and disposal of fly ash excluded.
- Total direct investment, $33,002,000; total depreciable investment, $61,407,000; and total capital investment, $63,217,000.
- All tons shown are 2,000 lb.

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TABLE A-135

WELLMAN-LORD/ ALLIED CHEMICAL PROCESS VARIATION FROM BASE CASE: WET SCRUBBING FLY ASH REMOVAL, REGULATED CO. ECONOMICS

TOTAL CAPITAL INVESTMENT 63217000

YEARS AFTER POWER UNIT START	ANNUAL OPERATION, KW-HR/KW	POWER UNIT HEAT REQUIREMENT, MILLION BTU /YEAR	POWER UNIT FUEL CONSUMPTION, TONS COAL /YEAR	SULFUR REMOVED BY POLLUTION CONTROL PROCESS, TONS/YEAR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: ELEMENTAL SULFUR	BY-PRODUCT RATE, EQUIVALENT TONS/YEAR: SODIUM SULFATE	NET REVENUE, $/TON: ELEMENTAL SULFUR	NET REVENUE, $/TON: SODIUM SULFATE	TOTAL OP. COST INCLUDING REGULATED ROI FOR POWER COMPANY, $/YEAR	TOTAL NE SALES REVENUE, $/YEAR	NET ANNUAL INCREASE (DECREASE) IN COST OF POWER, $	CUMULATIVE NET INCREASE (DECREASE) IN COST OF POWER, $
1	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26930600	1281600	25649000	25649000
2	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26578600	1281600	25297000	50946000
3	7000	31500000	1500000	34800	31000	8000	36.00	20.70	26226500	1281600	24944900	75890900
4	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25874400	1281600	24592800	100483700
5	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25522400	1281600	24240800	124724500
6	7000	31500000	1500000	34800	31000	8000	36.00	20.70	25170300	1281600	23888700	148613200
7	7000	31500000	1500000	34800	31000	8000	36.00	20.70	24818200	1281600	23536600	172149800
8	7000	31500000	1500000	34800	31000	8000	36.00	20.70	24466200	1281600	23184600	195334400
9	7000	31500000	1500000	34800	31000	8000	36.00	20.70	24114100	1281600	22832500	218166900
10	7000	31500000	1500000	34800	31000	8000	36.00	20.70	23762000	1281600	22480400	240647300
11	5000	22500000	1071400	24800	22100	5700	36.00	20.70	20302900	913600	19389300	260036600
12	5000	22500000	1071400	24800	22100	5700	36.00	20.70	19950800	913600	19037200	279073800
13	5000	22500000	1071400	24800	22100	5700	36.00	20.70	19598700	913600	18685100	297758900
14	5000	22500000	1071400	24800	22100	5700	36.00	20.70	19246700	913600	18333100	316092000
15	5000	22500000	1071400	24800	22100	5700	36.00	20.70	18896600	913600	17983000	334075000
16	3500	15750000	750000	17400	15500	4000	36.00	20.70	16131600	640800	15490800	349563800
17	3500	15750000	750000	17400	15500	4000	36.00	20.70	15779600	640800	15138800	364702600
18	3500	15750000	750000	17400	15500	4000	36.00	20.70	15427500	640800	14786700	379489300
19	3500	15750000	750000	17400	15500	4000	36.00	20.70	15075400	640800	14434600	393923900
20	3500	15750000	750000	17400	15500	4000	36.00	20.70	14723400	640800	14082600	408006500
21	1500	6750000	321400	7500	6600	1700	36.00	20.70	10942900	272800	10670100	418676600
22	1500	6750000	321400	7500	6600	1700	36.00	20.70	10590800	272800	10318000	428994600
23	1500	6750000	321400	7500	6600	1700	36.00	20.70	10238800	272800	9966000	438960600
24	1500	6750000	321400	7500	6600	1700	36.00	20.70	9886700	272800	9613900	448574500
25	1500	6750000	321400	7500	6600	1700	36.00	20.70	9534600	272800	9261800	457836300
26	1500	6750000	321400	7500	6600	1700	36.00	20.70	9182500	272800	8909800	466746100
27	1500	6750000	321400	7500	6600	1700	36.00	20.70	8830500	272800	8557700	475303800
28	1500	6750000	321400	7500	6600	1700	36.00	20.70	8478400	272800	8205600	483509400
29	1500	6750000	321400	7500	6600	1700	36.00	20.70	8126400	272800	7853600	491363000
30	1500	6750000	321400	7500	6600	1700	36.00	20.70	7774300	272800	7501500	498864500
TOT	127500	573750000	27321000	634000	564000	145500			522180500	23316000	498864500	

LIFETIME AVERAGE INCREASE (DECREASE) IN UNIT OPERATING COST

DOLLARS PER TON OF COAL BURNED	19.11	0.85	18.26
MILLS PER KILOWATT-HOUR	8.19	0.36	7.83
CENTS PER MILLION BTU HEAT INPUT	91.01	4.06	86.95
DOLLARS PER TON OF SULFUR REMOVED	823.63	36.78	786.85
PROCESS COST DISCOUNTED AT 11.5% TO INITIAL YEAR, DOLLARS	188354900	9095600	179259300

LEVELIZED INCREASE (DECREASE) IN UNIT OPERATING COST EQUIVALENT TO DISCOUNTED PROCESS COST OVER LIFE OF POWER UNIT

DOLLARS PER TON OF COAL BURNED	17.69	0.86	16.83
MILLS PER KILOWATT-HOUR	7.58	0.37	7.21
CENTS PER MILLION BTU HEAT INPUT	84.22	4.07	80.15
DOLLARS PER TON OF SULFUR REMOVED	762.57	36.82	725.75